NEI 99-02 Revision 4

Regulatory Assessment Performance Indicator Guideline

April 2006

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Nuclear Energy Institute

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ACKNOWLEDGMENTS

NOTICE

EXECUTIVE SUMMARY

In 2000 the Nuclear Regulatory Commission revised its regulatory oversight process for
inspection, assessment and enforcement of commercial nuclear power reactors. The new process
utilizes information obtained from licensee-reported performance indicators and NRC inspection
findings. The purpose of this manual is to provide the guidance necessary for power reactor
licensees to collect and report the data elements that will be used to compute the Performance
Indicators.

An overview of the complete oversight process is provided in NUREG 1649, "Reactor
Oversight Process." More detail is provided in SECY 99-007, "Recommendations for Reactor
Oversight Process Improvements," as amended in SECY 99-007A and SECY 00-049 "Results of
the Revised Reactor Oversight Process Pilot Program."

This revision is effective for data collection as of April 1, 2006.

Summary of Changes to NEI 99-02
Revision 3 to Revision 4

Page	Major Changes
i	Effective date of revision identified as April 1, 2006
7	Thresholds for MSPI indicators (MS06-MS10) added to Table 1
7	Deleted thresholds for SSU indicators (MS01-MS04)
14	Added additional example of unplanned scrams that do not count for IE02
21	Deleted SSU description contained in section 2.2
25	Added MSPI description in section 2.2
A-1	Updated list of abbreviations and acronyms
B-1	Revised data file reporting format to reflect addition of MSPI indicator and removal of SSU indicator reporting
D-1	Deleted plant specific issues associated with SSU indicators
F-1	Added Appendix F
G-1	Added Appendix G

Frequently Asked Questions

The following table identifies where NRC approved FAQs were incorporated in the text. Not all FAQs required a text change, and those FAQs are also identified. All of these FAQs will be placed in the archived FAQ file which is available on the NRC website for reference only.

Section	FAQs
Unplanned Scrams per 7,000 Critical Hours	382, 402
Drill/Exercise Performance	401
Alert and Notification System Reliability	396
Appendix D	None
No change in text	383, 384, 385, 386, 387, 388, 389, 390, 391, 392, 393, 394, 395, 397, 398, 399, 400

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Appendices

1   INTRODUCTION

This guideline describes the data and calculations for each performance indicator in the Nuclear Regulatory Commission's (NRC) power reactor licensee assessment process. The guideline also describes the licensee quarterly indicator reports that are to be submitted to the NRC for use in its licensee assessment process.

This guideline provides the definitions and guidance for the purposes of reporting performance indicator data. Responses to Frequently Asked Questions (FAQs) that have been approved by the Industry/NRC working group and posted on the NRC's external website become addenda to this guideline. No other documents should be used for definitions or guidance unless specifically referenced in this document. This guideline should not be used for purposes other than collection and reporting of performance indicator data in the NRC licensee assessment process.

Background

In 1998 and 1999, the NRC conducted a series of public meetings to develop a more objective process for assessing a licensee's regulatory and safety performance. The new process uses risk-informed insights to focus on those matters that are of safety significance. The objective is to monitor performance in three broad areas – reactor safety (avoiding accidents and reducing the consequences of accidents if they occur); radiation safety for plant workers and the public during routine operations; and protection of the plant against sabotage or other security threats.

The three broad areas are divided into cornerstones: initiating events, mitigating systems, barrier integrity, emergency preparedness, public radiation safety, occupational radiation safety and physical protection. Performance indicators are used to assess licensee performance in each cornerstone. The NRC will use a risk-informed baseline inspection process to supplement and complement the performance indicator(s). This guideline focuses on the performance indicator segment of the assessment process.

The thresholds for each performance indicator provide objective indication of the need to modify NRC inspection resources or to take other regulatory actions based on licensee performance. Table 1 provides a summary of the performance indicators and their associated thresholds.

The overall objectives of the process are to:

- improve the objectivity of the oversight processes so that subjective decisions and judgment are not central process features,
- improve the scrutability of the NRC assessment process so that NRC actions have a clear tie to licensee performance, and
- risk-inform the regulatory assessment process so that NRC and licensee resources are focused on those aspects of performance having the greatest impact on safe plant operation.

In identifying those aspects of licensee performance that are important to the NRC's mission, adequate protection of public health and safety, the NRC set high level performance goals for regulatory oversight. These goals are:

1
2 •   maintain a low frequency of events that could lead to a nuclear reactor accident;
3 •   zero significant radiation exposures resulting from civilian nuclear reactors;
4 •   no increase in the number of offsite releases of radioactive material from civilian nuclear
5   reactors that exceed 10 CFR Part 20 limits; and
6 •   no substantiated breakdown of physical protection that significantly weakens protection
7   against radiological sabotage, theft, or diversion of special nuclear materials.
8
9 These performance goals are represented in the new assessment framework as the strategic
10 performance areas of Reactor Safety, Radiation Safety, and Safeguards.
11
12 Figure 1.0 provides a graphical representation of the licensee assessment process.
13
14 **General Reporting Guidance**

15 At quarterly intervals, each licensee will submit to the NRC the performance assessment data
16 described in this guideline. The data is submitted electronically to the NRC by the 21st calendar
17 day of the month following the end of the reporting quarter. If a submittal date falls on a
18 Saturday, Sunday, or federal holiday; the next federal working day becomes the official due date
19 (in accordance with 10 CFR 50.4). The format and examples of the data provided in each
20 subsection show the complete data record for an indicator, and provide a chart of the indicator.
21 These are provided for illustrative purposes only. Each licensee only sends to the NRC the data
22 set from the previous quarter, as defined in each *Data Reporting Elements* subsection (See
23 Appendix B) along with any changes to previously submitted data.
24
25 The reporting of performance indicators is a separate and distinct function from other NRC
26 reporting requirements. Licensees will continue to submit other regulatory reports as required by
27 regulations; such as, 10 CFR 50.72 and 10 CFR 50.73.
28
29 Performance indicator reports are submitted to the NRC for each power reactor unit. Some
30 indicators are based on station parameters. In these cases the station value is reported for each
31 power reactor unit at the station.
32
33 Issues regarding interpretation or implementation of NEI 99-02 guidance may occur during
34 implementation. Licensees are encouraged to resolve these issues with the Region. In those
35 instances where the NRC staff and the Licensee are unable to reach resolution, or to address
36 plant specific exceptions, the issue should be escalated to appropriate industry and NRC
37 management using the FAQ process.[1] In the interim period until the issue is resolved, the
38 Licensee is encouraged to maintain open communication with the NRC. Issues involving
39 enforcement are not included in this process.
40

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[1] See additional information on Frequently Asked Questions in Appendix E, Frequently Asked Questions and
Appendix D, Plant Specific Design Issues.

1 **Guidance for Correcting Previously Submitted Performance Indicator Data**

2 In instances where data errors or a newly identified faulted condition are determined to have
3 occurred in a previous reporting period, previously submitted indicator data are amended only to
4 the extent necessary to correctly calculate the indicator(s) for the current reporting period.[2] This
5 amended information is submitted using a "change report" feature provided in the INPO
6 Consolidated Data Entry (CDE) software. The values of previous reporting periods are revised,
7 as appropriate, when the amended data is used by the NRC to recalculate the affected
8 performance indicator. The current report should reflect the new information, as discussed in the
9 detailed sections of this document. In these cases, the quarterly data report should include a
10 comment to indicate that the indicator values for past reporting periods are different than
11 previously reported. If an LER was required and the number is available at the time of the
12 report, the LER reference is noted.
13
14 If a performance indicator data reporting error is discovered, an amended "mid-quarter" report
15 does not need to be submitted if both the previously reported and amended performance indicator
16 values are within the "green" performance indicator band. In these instances, corrected data
17 should be included in the next quarterly report along with a brief description of the reason for the
18 change(s). If a performance indicator data error is discovered that causes a threshold to be
19 crossed, a "mid-quarter" report should be submitted as soon as practical following discovery of
20 the error.
21
22 **Comment Fields**

23 The quarterly report allows comments to be included with performance indicator data. A general
24 comment field is provided for comments pertinent to the quarterly submittal that are not specific
25 to an individual performance indicator. A separate comment field is provided for each
26 performance indicator. Comments included in the report should be brief and understandable by
27 the general public. Comments provided as part of the quarterly report will be included along
28 with performance indicator data as part of the NRC Public Web site on the oversight program. If
29 multiple PI comments are received by NRC that are applicable to the same unit/PI/quarter, the
30 NRC Public Web site will display all applicable comments for the quarter in the order received
31 (e.g., If a comment for the current quarter is received via quarterly report and a comment for the
32 same PI is received via a change report, then both comments will be displayed on the Web site.
33 For General Comments, the NRC Public Web site will display only the latest "general" comment
34 received for the current quarter (e.g., A "general" comment received via a change report will
35 replace any "general" comment provided via a previously submitted quarterly report.)
36
37 Comments should be generally limited to instances as directed in this guideline. These instances
38 include:
39 • Exceedance of a threshold (Comment should include a brief explanation and should be
40 repeated in subsequent quarterly reports as necessary to address the threshold exceedance)

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[2] Changes to data collection rules or practices required by the current revision of this document will not be applied
retroactively to previously submitted data. Previously submitted data will not require correction or amendment
provided it was collected and reported consistent with the NEI 99-02 revision and FAQ guidance in effect at the
time of submittal.

1 • Revision to previously submitted data (Comment should include a brief characterization of
2 the change, should identify affected time periods and should identify whether the change
3 affects the "color" of the indicator.)
4 • Unavailability of data for quarterly report (Examples include unavailability of RCS Activity
5 data for one or more months due to plant conditions that do not require RCS activity to be
6 calculated.)
7 • When an FAQ has been submitted that could impact the current or previously submitted data
8 • When a Safety System Functional Failure is reported, the LER number shall be listed
9 • If an NOED or technical specification change has been granted which would otherwise have
10 resulted in an unplanned power change of greater than 20% full power
11 • Failure to perform regularly scheduled ANS tests
12 • Changes in ANS test methodology
13
14 In specific circumstances, some plants, because of unique design characteristics, may typically
15 appear in the "increased regulatory response band," as shown in Table 1. In such cases the
16 unique condition and the resulting impact on the specific indicator should be explained in the
17 associated comment field. Additional guidance is provided under the appropriate indicator
18 sections.
19
20 The quarterly data reports are submitted to the NRC under 10 CFR 50.4 requirements. The
21 quarterly reports are to be submitted in electronic form only. Separate submittal of a paper copy
22 is not requested. Licensees should apply standard commercial quality practices to provide
23 reasonable assurance that the quarterly data submittals are correct. Licensees should plan to
24 retain the data consistent with the historical data requirements for each performance indicator.
25 For example, data associated with the barrier cornerstone should be retained for 12 months.
26
27 The criterion for reporting is based on the time the failure or deficiency is identified, with the
28 exception of the Safety System Functional Failure indicator, which is based on the Report Date
29 of the LER. In some cases the time of failure is immediately known, in other cases there may be
30 a time-lapse while calculations are performed to determine whether a deficiency exists, and in
31 some instances the time of occurrence is not known and has to be estimated. Additional
32 clarification is provided in specific indicator sections.
33
34 **Numerical Reporting Criteria**

35 Final calculations are rounded up or down to the same number of significant figures as shown in
36 Table 1. Where required, percentages are reported and noted as: 9.0%, 25%.
37
38 **Submittal of Performance Indicator Data**

39 Performance indicator data should be submitted as a delimited text file (data stream) for each
40 unit, attached to an email addressed to pidata@nrc.gov. The structure and format of the
41 delimited text files is discussed in Appendix B. The email message can include report files
42 containing PI data for the quarter (quarterly reports) for all units at a site and can also include
43 any report file(s) providing changes to previously submitted data (change reports). The
44 title/subject of the email should indicate the unit(s) for which data is included, the applicable
45 quarter, and whether the attachment includes quarterly report(s) (QR), change report(s) (CR) or
46 both. The recommended format of the email message title line is "<Plant Name(s)>-
47 <quarter/year>-PI Data Elements (QR and/or CR)" (e.g., "Salem Units 1 and 2 – 1Q2000 – PI

1   Data Elements (QR)"). Licensees should not submit hard copies of the PI data submittal (with
2   the possible exception of a back up if the email system is unavailable).
3
4   The NRC will send return emails with the licensee's submittal attached to confirm and
5   authenticate receipt of the proper data, generally within 2 business days. The licensee is
6   responsible for ensuring that the submitted data is received without corruption by comparing the
7   response file with the original file. Any problems with the data transmittal should be identified
8   in an email to pidata@nrc.gov within 4 business days of the original data transmittal.
9
10   Additional guidance on the collection of performance indicator data and the creation of quarterly
11   reports and change reports is provided in the INPO CDE Job Aids available on the INPO CDE
12   webpage.
13
14   The reports made to the NRC under the new regulatory assessment process are in addition to the
15   standard reporting requirements prescribed by NRC regulations.
16

1
2
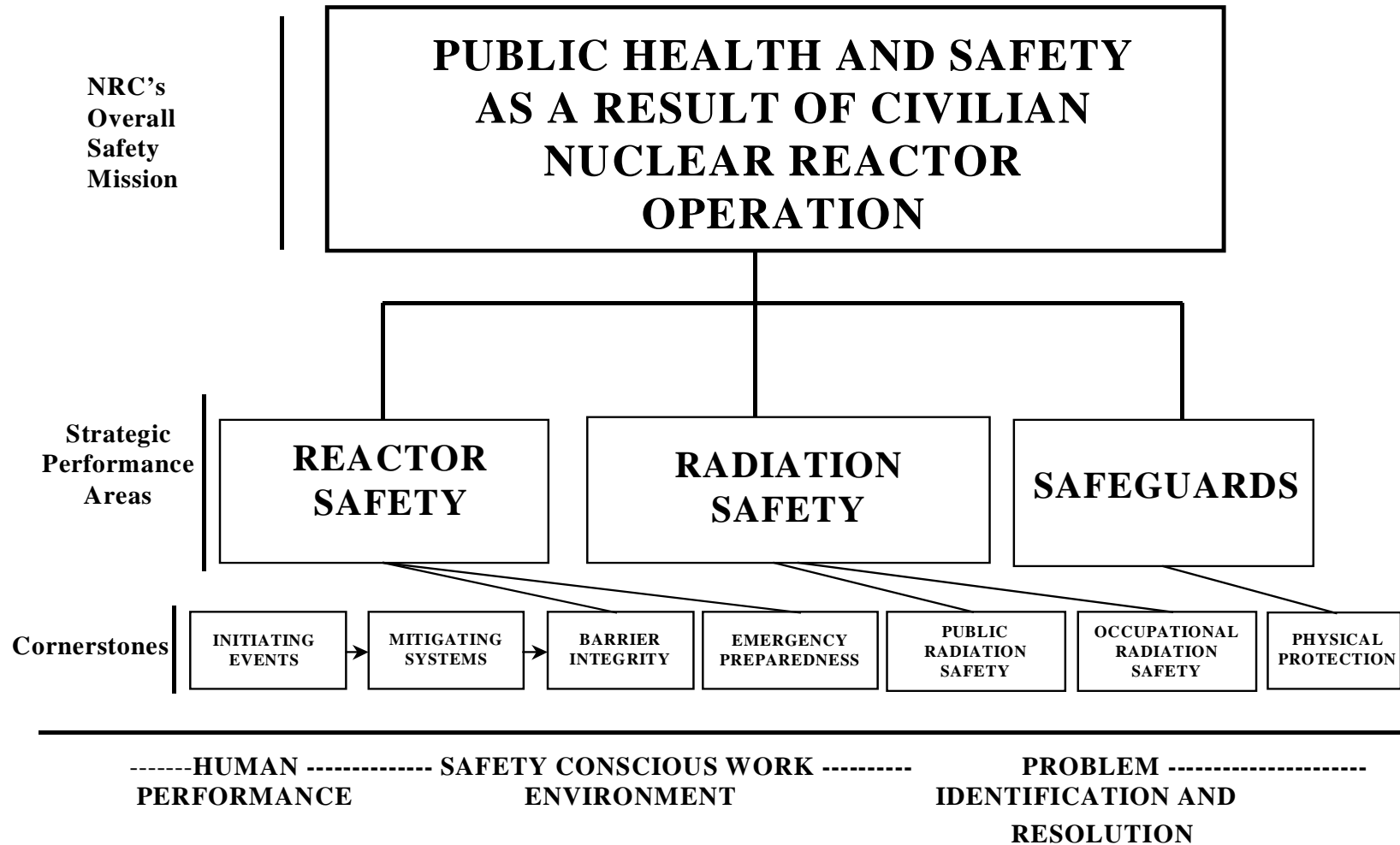
Figure 1 - Regulatory Oversight Framework

3
4
5
6

Table 1 – PERFORMANCE INDICATORS					
Cornerstone	**Indicator**		**Thresholds (see Note 1)**		
			Increased Regulatory Response Band	**Required Regulatory Response Band**	**Unacceptable Performance Band**
Initiating Events	**IE01**	Unplanned Scrams per 7000 Critical Hours (automatic and manual scrams during the previous four quarters)	>3.0	>6.0	>25.0
	IE02	Unplanned Scrams with a Loss of Normal Heat Removal (over the previous 12 quarters)	>2.0	>10.0	>20.0
	IE03	Unplanned Power Changes per 7000 Critical Hours (over previous four quarters)	>6.0	N/A	N/A
Mitigating Systems	**MS05**	Safety System Functional Failures (over previous four quarters) — BWRs / PWRs	>6.0 / >5.0	N/A / N/A	N/A / N/A
	MS06	Mitigating System Performance Index (Emergency AC Power Systems)	>1.0E-06 OR PLE = YES	>1.0E-05	>1.0E-04
	MS07	Mitigating System Performance Index (High Pressure Injection Systems)	>1.0E-06 OR PLE = YES	>1.0E-05	>1.0E-04
	MS08	Mitigating System Performance Index (Heat Removal Systems)	>1.0E-06 OR PLE = YES	>1.0E-05	>1.0E-04
	MS09	Mitigating System Performance Index (Residual Heat Removal Systems)	>1.0E-06 OR PLE = YES	>1.0E-05	>1.0E-04
	MS10	Mitigating System Performance Index (Cooling Water Systems)	>1.0E-06 OR PLE = YES	>1.0E-05	>1.0E-04
Barriers Fuel Cladding	**BI01**	Reactor Coolant System (RCS) Specific Activity (maximum monthly values, percent of Tech. Spec limit)	>50.0%	>100.0%	N/A
Reactor Coolant System	**BI02**	RCS Identified Leak Rate (maximum monthly values, percent of Tech. Spec. limit)	>50.0%	>100.0%	N/A

1

2   Note 1: Thresholds that are specific to a site or unit will be provided in Appendix D when identified.

3   Note 2: PLE – System Component Performance Limit Exceeded (see Appendix F, page F-39)

1

Table 1 - PERFORMANCE INDICATORS Cont'd					
Cornerstone	Indicator		Thresholds (see Note 1)		
			Increased Regulatory Response Band	Required Regulatory Response Band	Unacceptable Performance Band
Emergency Preparedness	EP01	Drill/Exercise Performance (over previous eight quarters)	<90.0%	<70.0%	N/A
	EP02	ERO Drill Participation (percentage of Key ERO personnel that have participated in a drill or exercise in the previous eight quarters)	<80.0%	<60.0%	N/A
	EP03	Alert and Notification System Reliability (percentage reliability during previous four quarters)	<94.0%	<90.0%	N/A
Occupational Radiation Safety	OR01	Occupational Exposure Control Effectiveness (occurrences during previous 4 quarters)	>2	>5	N/A
Public Radiation Safety	PR01	RETS/ODCM Radiological Effluent Occurrence (occurrences during previous four quarters)	>1	>3	N/A
Physical Protection	PP01	Protected Area Security Equipment Performance Index (over a four quarter period)	>0.080	N/A	N/A
	PP02	Personnel Screening Program Performance (reportable events during the previous four quarters)	>2	>5	N/A
	PP03	Fitness-for-Duty (FFD)/Personnel Reliability Program Performance (reportable events during the previous four quarters)	>2	>5	N/A

2

3   Note 1: Thresholds that are specific to a site or unit will be provided in Appendix D when identified.

4

2   PERFORMANCE INDICATORS

2.1 INITIATING EVENTS CORNERSTONE

The objective of this cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions, during shutdown[3] as well as power operations. If not properly mitigated, and if multiple barriers are breached, a reactor accident could result which may compromise the public health and safety. Licensees can reduce the likelihood of a reactor accident by maintaining a low frequency of these initiating events. Such events include reactor scrams due to turbine trips, loss of feedwater, loss of off-site power, and other significant reactor transients.

The indicators for this cornerstone are reported and calculated per reactor unit.

There are three indicators in this cornerstone:

- Unplanned (automatic and manual) scrams per 7,000 critical hours
- Scrams with a loss of normal heat removal per 12 quarters
- Unplanned Power Changes per 7,000 critical hours

UNPLANNED SCRAMS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of unplanned scrams. It measures the rate of scrams per year of operation at power and provides an indication of initiating event frequency.

Indicator Definition

The number of unplanned scrams during the previous four quarters, both manual and automatic, while critical per 7,000 hours.

Data Reporting Elements

The following data are reported for each reactor unit:

- the number of unplanned automatic and manual scrams while critical in the previous quarter

- the number of hours of critical operation in the previous quarter

---

[3]Shutdown indicators are being developed and will be included in later revisions.

1   **Calculation**

2   The indicator is determined using the values for the previous four quarters as follows:
3

4
$$\text{value} = \frac{(\text{total unplanned scrams while critical in the previous 4 qtrs}) \times 7{,}000 \text{ hrs}}{(\text{total number of hours critical in the previous 4 qtrs})}$$

5
6   **Definition of Terms**

7   *Scram* means the shutdown of the reactor by the rapid addition of negative reactivity by any
8   means, e.g., insertion of control rods, boron, use of diverse scram switch, or opening reactor trip
9   breakers.
10
11   *Unplanned scram* means that the scram was not an intentional part of a planned evolution or test
12   as directed by a normal operating or test procedure. This includes scrams that occurred during
13   the execution of procedures or evolutions in which there was a high chance of a scram occurring
14   but the scram was neither planned nor intended.
15
16   *Criticality,* for the purposes of this indicator, typically exists when a licensed reactor operator
17   declares the reactor critical. There may be instances where a transient initiates from a subcritical
18   condition and is terminated by a scram after the reactor is critical—this condition would count as
19   a scram.
20
21   **Clarifying Notes**

22   The value of 7,000 hours is used because it represents one year of reactor operation at about an
23   80% availability factor.
24
25   If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is
26   displayed as N/A because rate indicators can produce misleadingly high values when the
27   denominator is small. The data elements (unplanned scrams and critical hours) are still reported.
28
29   Dropped rods, single rod scrams, or half scrams are not considered reactor scrams. Partial rod
30   insertions, such as runbacks, and rod insertion by the control system at normal speed also do not
31   count unless the resulting conditions subsequently cause a reactor scram.
32
33   Anticipatory plant shutdowns intended to reduce the impact of external events, such as tornadoes
34   or range fires threatening offsite power transmission lines, are excluded.
35
36   Examples of the types of scrams that **are included**:
37
38   • Scrams that resulted from unplanned transients, equipment failures, spurious signals, human
39   error, or those directed by abnormal, emergency, or annunciator response procedures.
40
41   • A scram that is initiated to avoid exceeding a technical specification action statement time
42   limit.
43
44   • A scram that occurs during the execution of a procedure or evolution in which there is a high
45   likelihood of a scram occurring but the scram was neither planned nor intended.

1
2 Examples of scrams that **are not** included:
3
4 •   Scrams that are planned to occur as part of a test (e.g., a reactor protection system
5   actuation test), or scrams that are part of a normal planned operation or evolution.
6
7 •   Reactor protection system actuation signals or operator actions to trip the reactor that occur
8   while the reactor is sub-critical.
9
10 •   Scrams that occur as part of the normal sequence of a planned shutdown and scram signals
11   that occur while the reactor is shut down.
12
13 •   Plant shutdown to comply with technical specification LCOs, if conducted in accordance
14   with normal shutdown procedures which include a manual scram to complete the
15   shutdown.
16
17

1   **Data Example**

Unplanned Scrams per 7,000 Critical Hours									
	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr	
# of Scrams critical in qtr	1	0	0	1	1	1	2	2	
Total Scrams over 4 qtrs				2	2	3	5	6	
# of Hrs Crit in qtr	1500	1000	2160	2136	2160	2136	2136	1751	
Total Hrs Critical in 4 qtrs				6796	7456	8592	8568	8183	
					2Q/98	3Q/98	4Q/98	Prev. Q	
Indicator value					1.9	2.4	4.1	5.1	

Thresholds	
Green	≤3.0
White	>3.0
Yellow	>6.0
Red	>25.0

Unplanned Scrams per 7,000 Hrs

2
3
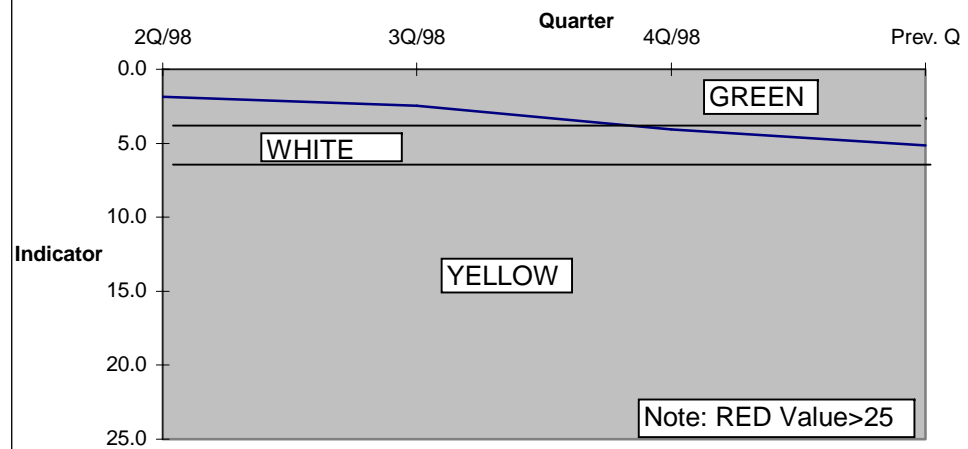
1 | UNPLANNED SCRAMS WITH LOSS OF NORMAL HEAT REMOVAL

2 **Purpose**

3 This indicator monitors that subset of unplanned automatic and manual scrams that were
4 complicated by the loss of the normal heat removal path either prior to the scram or during the
5 scram recovery. Such events or conditions are more risk-significant than uncomplicated scrams.
6
7 **Indicator Definition**

8 The number of unplanned scrams while critical, both manual and automatic, during the previous
9 12 quarters that were either caused by or involved a loss of the normal heat removal path prior
10 to establishing reactor conditions that allow use of the plant's normal long term heat removal
11 systems.
12
13 **Data Reporting Elements**

14 The following data are reported for each reactor unit:
15
16 • the number of unplanned automatic and manual scrams while critical in the previous
17 quarter that were either caused by or involved a loss of the normal heat removal path
18 prior to establishing reactor conditions that allow use of the plant's normal long term heat
19 removal systems.
20
21 **Calculation**

22 The indicator is determined using the values reported for the previous 12 quarters as follows:
23
24 value = total unplanned scrams while critical in the previous 12 quarters that were either
25 caused by or involved a loss of the normal heat removal path   prior to
26 establishing reactor conditions that allow use of the plant's normal long term
27 heat removal systems.
28
29 **Definition of Terms**

30 *Normal heat removal path:* for purposes of this performance indicator, the path used for heat
31 removal from the reactor during normal plant operations. It is the same for all plants – the path
32 from the main condenser through the main feedwater system, the steam generators (PWRs) or
33 reactor vessel (BWRs), the main steam isolation valves (MSIVs), the turbine bypass valves, and
34 back to the main condenser.
35
36 *Loss of the normal heat removal path:* when any of the following conditions have occurred and
37 cannot be easily recovered from the control room without the need for diagnosis or repair to
38 restore the normal heat removal path:
39
40 • complete loss of all main feedwater flow
41 • insufficient main condenser vacuum to remove decay heat
42 • complete closure of at least one MSIV in each main steam line

1   • failure of turbine bypass capacity that results in insufficient bypass capability remaining to
2   maintain reactor temperature and pressure
3
4   *Scram* means the shutdown of the reactor by the rapid addition of negative reactivity by any
5   means, e.g., insertion of control rods, boron, use of diverse scram switch, or opening reactor trip
6   breakers.
7
8   *Criticality,* for the purposes of this indicator, typically exists when a licensed reactor operator
9   declares the reactor critical. There may be instances where a transient initiates from a subcritical
10 condition and is terminated by a scram after the reactor is critical—this condition would count as
11 a scram.
12
13 **Clarifying Notes**

14 *Loss of normal heat removal path* means the loss of the normal heat removal path as defined
15 above. The determining factor for this indicator is whether or not the normal heat removal path is
16 *available*, not whether the operators choose to use that path or some other path.
17
18 *Operator actions or design features to control the reactor cooldown rate or water level*, such as
19 closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long
20 as the normal heat removal path can be readily recovered from the control room without the need
21 for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the
22 safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported.
23
24 *Examples of a complete loss of all main feedwater flow: loss* of all feedwater pumps during
25 startup or while operating at reduced power; loss of all startup and auxiliary feedwater pumps
26 normally used during plant startup; loss of all operating feed pumps following a scram due to
27 trips caused by low suction pressure, loss of seal water, or high water level (BWR reactor level
28 or PWR steam generator level); unplanned scram due to loss of all operating feed pumps; manual
29 scram in response to feed problems characteristic of a total loss of feedwater flow but prior to
30 automatic reactor protection system signals; and inadvertent isolation or closure of all feedwater
31 control valves prior to an unplanned scram.
32
33 *Example of loss of turbine bypass capability:* sustained use of one or more atmospheric dump
34 valves (PWRs) or safety relief valves to the suppression pool (BWRs) after an unplanned scram.
35
36 *Examples that do not count:* loss of all main feedwater flow, condenser vacuum, or turbine
37 bypass capability caused by full or partial loss of offsite power; partial losses of condenser
38 vacuum or turbine bypass capability after an unplanned scram in which sufficient capability
39 remains to remove decay heat; momentary operation of PORVs or safety relief valves; an
40 unplanned scram at low power within the capability of the PORVs if the main condenser has not
41 yet been placed in service or has been removed from service prior to the unplanned scram; and
42 breaking condenser vacuum to reduce turbine vibrations when starting up from an outage with
43 low decay heat, provided there were no complications.
44
45 This indicator includes unplanned scrams. Unplanned scrams counted for this indicator are also
46 counted for the *Unplanned Scrams per 7000 Critical Hours* indicator.

1   **Data Examples**

Unplanned Scrams with Loss of Normal Heat Removal

	3Q/95	4Q/95	1Q/96	2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qrtr
# of Scrams with loss of	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
NHR in prev qtr															
Total over 12 qtrs												1	1	0	0
												2Q/98	3Q/98	4Q/98	Prev. Q
Indicator value												1	1	0	0

Thresholds	
Green	≤2.0
White	>2.0
Yellow	>10.0
Red	>20.0
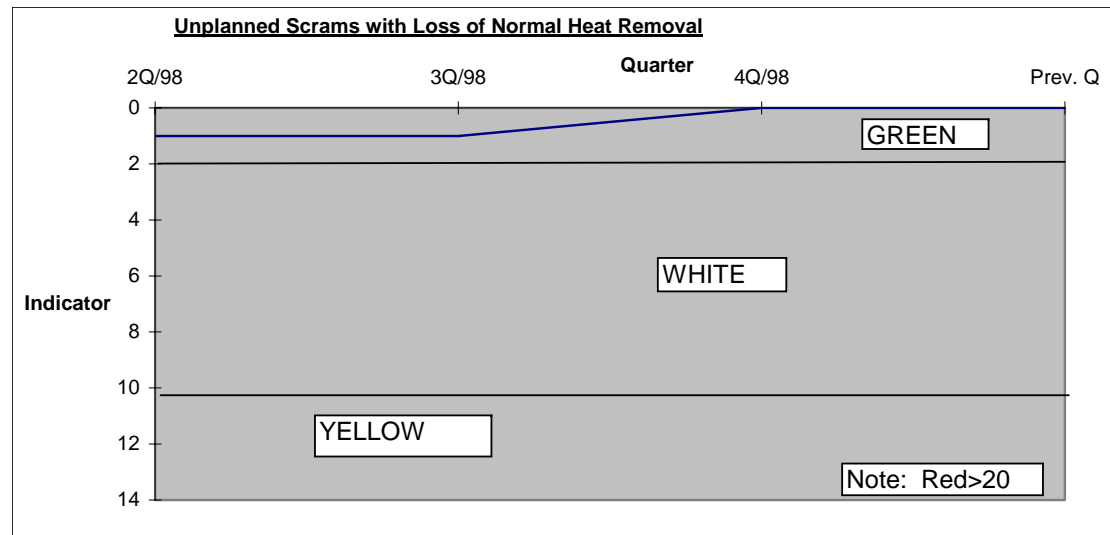
Unplanned Scrams with Loss of Normal Heat Removal

2
3

1 | **UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS**

2 **Purpose**

3 This indicator monitors the number of unplanned power changes (excluding scrams) that could
4 have, under other plant conditions, challenged safety functions. It may provide leading
5 indication of risk-significant events but is not itself risk-significant. The indicator measures the
6 number of plant power changes for a typical year of operation at power.
7
8 **Indicator Definition**

9 The number of unplanned changes in reactor power of greater than 20% of full-power, per 7,000
10 hours of critical operation excluding manual and automatic scrams.
11
12 **Data Reporting Elements**

13 The following data is reported for each reactor unit:
14
15 • the number of unplanned power changes, excluding scrams, during the previous quarter
16
17 • the number of hours of critical operation in the previous quarter
18
19 **Calculation**

20 The indicator is determined using the values reported for the previous four quarters as follows:
21

22 $$\text{value} = \frac{(\text{total number of unplanned power changes over the previous 4 qtrs})}{\text{total number of hours critical during the previous 4 qtrs}} \times 7,000 \text{ hrs}$$

23
24 **Definition of Terms**

25 *Unplanned changes in reactor power* are changes in reactor power that are initiated less than 72
26 hours following the discovery of an off-normal condition, and that result in, or require a change
27 in power level of greater than 20% of full power to resolve. Unplanned changes in reactor power
28 also include uncontrolled excursions of greater than 20% of full power that occur in response to
29 changes in reactor or plant conditions and are not an expected part of a planned evolution or test.
30
31 **Clarifying Notes**

32 The value of 7,000 hours is used because it represents one year of reactor operation at about an
33 80% availability factor.
34
35 If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is
36 displayed as N/A because rate indicators can produce misleadingly high values when the
37 denominator is small. The data elements (unplanned power changes and critical hours) are still
38 reported.
39
40 The 72 hour period between discovery of an off-normal condition and the corresponding change
41 in power level is based on the typical time to assess the plant condition, and prepare, review, and

1 approve the necessary work orders, procedures, and necessary safety reviews, to effect a repair.
2 The key element to be used in determining whether a power change should be counted as part of
3 this indicator is the 72 hour period and not the extent of the planning that is performed between
4 the discovery of the condition and initiation of the power change.
5
6 In developing a plan to conduct a power reduction, additional contingency power reductions may
7 be incorporated. These additional power reductions are not counted if they are implemented to
8 address the initial condition.
9
10 Equipment problems encountered during a planned power reduction greater than 20% that alone
11 may have required a power reduction of 20% or more to repair are not counted as part of this
12 indicator if they are repaired during the planned power reduction. However, if during the
13 implementation of a planned power reduction, power is reduced by more than 20% of full power
14 beyond the planned reduction, then an unplanned power change has occurred.
15
16 Unplanned power changes and shutdowns include those conducted in response to equipment
17 failures or personnel errors and those conducted to perform maintenance. They do not include
18 automatic or manual scrams or load-follow power changes.
19
20 Apparent power changes that are determined to be caused by instrumentation problems are not
21 included.
22
23 Unplanned power changes include runbacks and power oscillations greater than 20% of full
24 power. A power oscillation that results in an unplanned power decrease of greater than 20%
25 followed by an unplanned power increase of 20% should be counted as two separate PI events,
26 unless the power restoration is implemented using approved procedures. For example, an
27 operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in
28 power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action
29 and closes the breaker resulting in a power increase of greater than 20%. Both transients would
30 count since they were the result of two separate errors (or unplanned/non-proceduralized action).
31
32 If conditions arise that would normally require unit shutdown, and an NOED is granted that
33 allows continued operation before power is reduced greater than 20%, an unplanned power
34 change is not reported because no actual change in power greater than 20% of full power
35 occurred. However, a comment should be made that the NRC had granted an NOED during the
36 quarter, which, if not granted, may have resulted in an unplanned power change.
37
38 Anticipatory power reductions intended to reduce the impact of external events such as
39 hurricanes or range fires threatening offsite power transmission lines, and power changes
40 requested by the system load dispatchers, are excluded.
41
42 Anticipated power changes greater than 20% in response to expected environmental problems
43 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are
44 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be
45 counted unless they are reactive to the sudden discovery of off-normal conditions. However,
46 unique environmental conditions which have not been previously experienced and could not
47 have been anticipated and mitigated by procedure or plant modification, may not count, even if
48 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine

1   or other biological growth from causing power reductions. Intrusion events that can be
2   anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would
3   normally be counted unless the down power was planned 72 hours in advance. The
4   circumstances of each situation are different and should be identified to the NRC in a FAQ so
5   that a determination can be made concerning whether the power change should be counted.
6
7   Power changes to make rod pattern adjustments are excluded.
8
9   Power changes directed by the load dispatcher under normal operating conditions due to load
10 demand, for economic reasons, for grid stability, or for nuclear plant safety concerns arising
11 from external events outside the control of the nuclear unit are not included in this indicator.
12 However, power reductions due to equipment failures that are under the control of the nuclear
13 unit are included in this indicator.
14
15 Licensees should use the power indication that is used to control the plant to determine if a
16 change of greater than 20% of full power has occurred.
17
18 This indicator captures changes in reactor power that are initiated following the discovery of an
19 off-normal condition. If a condition is identified that is slowly degrading and the licensee
20 prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have
21 elapsed since the condition was first identified, the power change does not count. If, however,
22 the condition suddenly degrades beyond the predefined limits and requires rapid response, this
23 situation would count.
24
25 Off-normal conditions that begin with one or more power reductions and end with an unplanned
26 reactor trip are counted in the unplanned reactor scram indicator only. However, if the cause of
27 the downpower(s) and the scram are different, an unplanned power change and an unplanned
28 scram must both be counted. For example, an unplanned power reduction is made to take the
29 turbine generator off line while remaining critical to repair a component. However, when the
30 generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs.
31 In this case, both an unplanned power change and an unplanned scram would be counted. If an
32 off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor
33 trip using normal operating procedures, only an unplanned power change is counted.
34
35 Downpowers of greater than 20% of full power for ALARA reasons are counted in the indicator.

1   **Data Example**

Unplanned Power Changes per 7,000 Critical Hours

	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
# of Power Changes in previous qtr	1	0	0	1	2	2	1	3
Total Power Changes in previous 4 qtrs	1	1	1	2	3	5	6	8
# of Hrs Critical in qrtr	1500	1000	2160	2136	2160	2136	2136	1751
Total Hrs Critical in previous 4 qtrs				6796	7456	8592	8568	8183
					2Q/98	3Q/98	4Q/98	Prev. Q
Indicator value					2.8	4.1	4.9	6.8

Thresholds	
Green	≤6.0
White	>6.0
Yellow	N/A
Red	N/A

Unplanned Power Changes per 7,000 Critical Hrs
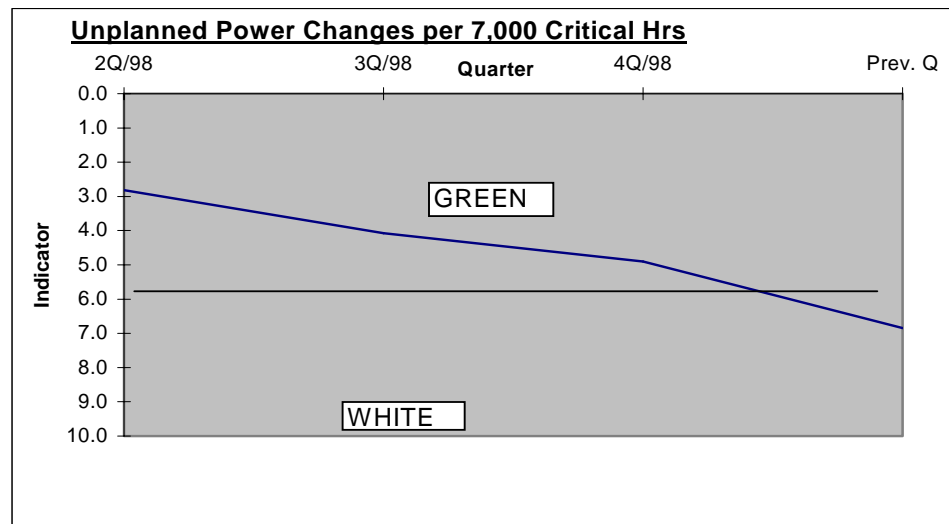
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1   **2.2   MITIGATING SYSTEMS CORNERSTONE**

2   The objective of this cornerstone is to monitor the availability, reliability, and capability of
3   systems that mitigate the effects of initiating events to prevent core damage. Licensees reduce
4   the likelihood of reactor accidents by maintaining the availability and reliability of mitigating
5   systems. Mitigating systems include those systems associated with safety injection, decay heat
6   removal, and their support systems, such as emergency AC power. This cornerstone includes
7   mitigating systems that respond to both operating and shutdown events.
8
9   The definitions and guidance contained in this section, while similar to guidance developed in
10 support of INPO/WANO indicators and the Maintenance Rule, are unique to the Reactor
11 Oversight Process (ROP). Differences in definitions and guidance in most instances are
12 deliberate and are necessary to meet the unique requirements of the ROP.
13
14 While safety systems are generally thought of as those that are designed to mitigate design basis
15 accidents, not all mitigating systems have the same risk importance. PRAs have shown that risk
16 is often influenced not only by front-line mitigating systems, but also by support systems and
17 equipment. Such systems and equipment, both safety- and non-safety related, have been
18 considered in selecting the performance indicators for this cornerstone. Not all aspects of
19 licensee performance can be monitored by performance indicators, and risk-informed baseline
20 inspections are used to supplement these indicators.
21
22
23 | SAFETY SYSTEM FUNCTIONAL FAILURES |
    | --- |

24 **Purpose**

25 This indicator monitors events or conditions that prevented, or could have prevented, the
26 fulfillment of the safety function of structures or systems that are needed to:
27
28 (a) Shut down the reactor and maintain it in a safe shutdown condition;
29 (b) Remove residual heat;
30 (c) Control the release of radioactive material; or
31 (d) Mitigate the consequences of an accident.
32
33 **Indicator Definition**

34 The number of events or conditions that prevented, or could have prevented, the fulfillment of
35 the safety function of structures or systems in the previous four quarters.
36
37 **Data Reporting Elements**

38 The following data is reported for each reactor unit:
39
40 •   the number of safety system functional failures during the previous quarter
41

1   **Calculation**

2   unit value = number of safety system functional failures in previous four quarters
3
4   **Definition of Terms**

5   *Safety System Function Failure (SSFF)* is any event or condition that could have prevented the
6   fulfillment of the safety function of structures or systems that are needed to:
7
8   (A) Shut down the reactor and maintain it in a safe shutdown condition;
9   (B) Remove residual heat;
10 (C) Control the release of radioactive material; or
11 (D) Mitigate the consequences of an accident.
12
13 The indicator includes a wide variety of events or conditions, ranging from actual failures on
14 demand to potential failures attributable to various causes, including environmental qualification,
15 seismic qualification, human error, design or installation errors, etc. Many SSFFs do not involve
16 actual failures of equipment.
17
18 Because the contribution to risk of the structures and systems included in the SSFF varies
19 considerably, and because potential as well as actual failures are included, it is not possible to
20 assign a risk-significance to this indicator. It is intended to be used as a possible precursor to
21 more important equipment problems, until an indicator of safety system performance more
22 directly related to risk can be developed.
23

24 **Clarifying Notes**

25 *The definition of SSFFs* is identical to the wording of the current revision to 10 CFR
26 50.73(a)(2)(v). Because of overlap among various reporting requirements in 10 CFR 50.73,
27 some events or conditions that result in safety system functional failures may be properly
28 reported in accordance with other paragraphs of 10 CFR 50.73, particularly paragraphs (a)(2)(i),
29 (a)(2)(ii), and (a)(2)(vii). An event or condition that meets the requirements for reporting under
30 another paragraph of 10 CFR 50.73 should be evaluated to determine if it also prevented the
31 fulfillment of a safety function. Should this be the case, the requirements of paragraph (a)(2)(v)
32 are also met and the event or condition should be included in the quarterly performance indicator
33 report as an SSFF. The level of judgment for reporting an event or condition under paragraph
34 (a)(2)(v) as an SSFF is a reasonable expectation of preventing the fulfillment of a safety
35 function.
36
37 In the past, LERs may not have explicitly identified whether an event or condition was reportable
38 under 10 CFR 50.73(a)(2)(v) (i.e., all pertinent boxes may not have been checked). It is
39 important to ensure that the applicability of 10 CFR 50.73(a)(2)(v) has been explicitly considered
40 for each LER considered for this performance indicator.
41
42 *NUREG-1022:* Unless otherwise specified in this guideline, guidance contained in the latest
43 revision to NUREG-1022, "Event Reporting Guidelines, 10CFR 50.72 and 50.73," that is
44 applicable to reporting under 10 CFR 50.73(a)(2)(v), should be used to assess reportability for
45 this performance indicator. Questions regarding interpretation of NUREG-1022 should not be

referred to the FAQ process. They must be addressed to the appropriate NRC branch responsible
for NUREG-1022.

Planned Evolution for maintenance or surveillance testing: NUREG-1022, Revision 2, page 56
states, "The following types of events or conditions generally are not reportable under these
criteria:…Removal of a system or part of a system from service as part of a <u>planned</u> evolution
for maintenance or surveillance testing…"

"Planned" means the activity is undertaken voluntarily, at the licensee's discretion, and is not
required to restore operability or for continued plant operation.

A single event or condition that affects several systems: counts as only one failure.

Multiple occurrences of a system failure: the number of failures to be counted depends upon
whether the system was declared operable between occurrences. If the licensee knew that the
problem existed, tried to correct it, and considered the system to be operable, but the system was
subsequently found to have been inoperable the entire time, multiple failures will be counted
whether or not they are reported in the same LER. But if the licensee knew that a potential
problem existed and declared the system inoperable, subsequent failures of the system for the
same problem would not be counted as long as the system was not declared operable in the
interim. Similarly, in situations where the licensee did not realize that a problem existed (and
thus could not have intentionally declared the system inoperable or corrected the problem), only
one failure is counted.

Additional failures: a failure leading to an evaluation in which additional failures are found is
only counted as one failure; new problems found during the evaluation are not counted, even if
the causes or failure modes are different. The intent is to not count additional events when
problems are discovered while resolving the original problem.

Engineering analyses: events in which the licensee declared a system inoperable but an
engineering analysis later determined that the system was capable of performing its safety
function are not counted, even if the system was removed from service to perform the analysis.

Reporting date: the date of the SSFF is the Report Date of the LER.

The LER number should be entered in the comment field when an SSFF is reported.

1   **Data Examples**

Safety System Functional Failures

Quarter	2Q/98	3Q/98	4Q/98	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
SSFF in the previous qtr	1	3	2	1	1	2	0	1
					2Q/98	3Q/98	4Q/98	Prev. Q
Indicator: Number of SSFs over 4 Qtrs					7	6	4	4

Threshold for PWRs	
Green	≤5
White	>5
Yellow	N/A
Red	N/A

Safety System Functional Failures

2

3

1	**MITIGATING SYSTEM PERFORMANCE INDEX**

2
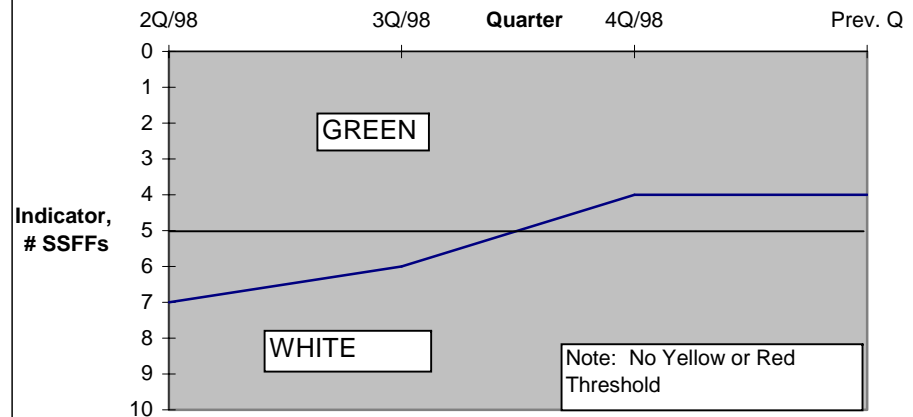
3   **Purpose**

4   The purpose of the Mitigating System Performance Index is to monitor the performance of
5   selected systems based on their ability to perform risk-significant functions as defined herein. It
6   is comprised of three elements - system unavailability, system unreliability and system
7   component performance limits. The index is used to determine the cumulative significance of
8   failures and unavailability over the monitored time period.

9

10   **Indicator Definition**

11   *Mitigating System Performance Index* (MSPI) is the sum of changes in a simplified core damage
12   frequency evaluation resulting from differences in unavailability and unreliability relative to
13   industry standard baseline values. The MSPI is supplemented with system component
14   performance limits.

15   *Unavailability* is the ratio of the hours the train/system was unavailable to perform its monitored
16   functions (as defined by PRA success criteria and mission times) due to planned and unplanned
17   maintenance or test during the previous 12 quarters while critical to the number of critical hours
18   during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are
19   counted only from the time of discovery of a failed condition to the time the train's monitored
20   functions are recovered.)

21   *Unreliability* is the probability that the train/system would not perform its monitored functions,
22   as defined by PRA success criteria and mission times, when called upon during the previous 12
23   quarters.

24   *Baseline values* are the values for unavailability and unreliability against which current plant
25   unavailability and unreliability are measured.

26   *Component performance limit* is a measure of degraded performance that indicates when the
27   performance of a monitored component in an MSPI system is significantly lower than expected
28   industry performance.

29

30   The MSPI is calculated separately for each of the following five systems for each reactor type.

31

32   **BWRs**

33   • emergency AC power system
34   • high pressure injection system (high pressure coolant injection, high pressure core spray,
35   or feedwater coolant injection)
36   • reactor core isolation cooling(or isolation condenser)
37   • residual heat removal system (or the equivalent function as described in the Additional
38   Guidance for Specific Systems section of Appendix F)
39   • cooling water support system (includes direct cooling functions provided by service
40   water and component cooling water or their cooling water equivalents for the above four
41   monitored systems)
42

PWRs

- emergency AC power system
- high pressure safety injection system
- auxiliary feedwater system
- residual heat removal system (or the equivalent function as described in the Additional Guidance for Specific Systems section of Appendix F)
- cooling water support system (includes direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

Data Reporting Elements

The following data elements are reported for each system

- Unavailability Index (UAI) due to unavailability for each monitored system

- Unreliability Index (URI) due to unreliability for each monitored system

- Systems that have exceeded their component performance limits

Calculation

The MSPI for each system is the sum of the UAI due to unavailability for the system plus URI due to unreliability for the system during the previous twelve quarters.

$MSPI = UAI + URI$

Component performance limits for each system are calculated as a maximum number of allowed failures (Fm) from the plant specific number of system demands and run hours. Actual numbers of equipment failures (Fa) are compared to these limits. This part of the indicator only applies to the green-white threshold.

See Appendix F for the calculation methodology for UAI due to system unavailability, URI due to system unreliability and system component performance limits.

The decision rules for assigning a performance color to a system are:

$\text{IF}[(MSPI \leq 1.0e\text{-}06) \text{ AND} (Fa \leq Fm)]$ THEN performance is GREEN

$\text{IF}\{[(MSPI \leq 1.0e\text{-}06) \text{ AND} (Fa > Fm)] \text{ OR } [(MSPI > 1.0e\text{-}06) \text{ AND} (MSPI \leq 1.0e\text{-}05)]\}$ THEN performance is WHITE

$\text{IF}[(MSPI > 1.0e\text{-}05) \text{ AND} (MSPI \leq 1.0e\text{-}04)]$ THEN performance is YELLOW

$\text{IF}(MSPI > 1.0e\text{-}04)$ THEN performance is RED

Plant Specific PRA

The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus,

1   the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder
2   of that quarter.

3   Specific requirements appropriate for this PRA application are defined in Appendix G. Any
4   questions related to the interpretation of these requirements, the use of alternate methods to meet
5   the requirements or the conformance of a plant specific PRA to these requirements will be
6   arbitrated by an Industry/NRC expert panel. If the panel determines that a plant specific PRA
7   does not meet the requirements of Appendix G such that the MSPI would be adversely affected,
8   an appropriate remedy will be determined by the licensee and approved by the panel. The
9   decisions of this panel will be binding.

10

Definition of Terms

12   *Risk Significant Functions*: those at power functions, described in the Appendix F section
13   "Additional Guidance for Specific Systems," that were determined to be risk-significant in
14   accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption
15   request). The risk significant system functions described in Appendix F, "Additional Guidance
16   for Specific Systems" should be modeled in the plant's PRA/PSA. System and equipment
17   performance requirements for performing the risk significant functions are determined from the
18   PRA success criteria for the system.

19   *Mission Time*: The mission time modeled in the PRA for satisfying the function of reaching a
20   stable plant condition where normal shutdown cooling is sufficient. Note that PRA models
21   typically use a mission time of 24 hours. However, shorter intervals, as justified by analyses and
22   modeled in the PRA, may be used.

23   *Success criteria*: The plant specific values of parameters the train/system is required to achieve
24   to perform its monitored functions. Success criteria to be used are those documented in the plant
25   specific PRA. Design Basis success criteria should be used in the case where the plant specific
26   PRA has not documented alternative success criteria for use in the PRA.

27   Individual component capability must be evaluated against train/system level success criteria
28   (e.g., a valve stroke time may exceed an ASME requirement, but if the valve still strokes in time
29   to meet the PRA success criteria for the train/system, the component has not failed for the
30   purposes of this indicator.).

31

Clarifying Notes

Documentation

34   Each licensee will have the system boundaries, monitored components, and monitored functions
35   and success criteria which differ from design basis readily available for NRC inspection on site.
36   Design basis criteria do not need to be separately documented. Additionally, plant-specific
37   information used in Appendix F should also be readily available for inspection. An acceptable
38   format, listing the minimum required information, is provided in Appendix G**.**

Monitored Systems

40   Systems have been generically selected for this indicator based on their importance in preventing
41   reactor core damage. The systems include the principal systems needed for maintaining reactor
42   coolant inventory following a loss of coolant accident, for decay heat removal following a
43   reactor trip or loss of main feedwater, and for providing emergency AC power following a loss

1 of plant off-site power. One support function (cooling water support system) is also monitored.
2 The cooling water support system monitors the cooling functions provided by service water and
3 component cooling water, or their direct cooling water equivalents, for the four front-line
4 monitored systems. No support systems are to be cascaded onto the monitored systems, e.g.,
5 HVAC room coolers, DC power, instrument air, etc.

6 **Diverse Systems**

7 Except as specifically stated in the indicator definition and reporting guidance, no credit is given
8 for the achievement of a monitored function by an unmonitored system in determining
9 unavailability or unreliability of the monitored systems.

10 **Use of Plant-Specific PRA and SPAR Models**

11 The MSPI is an approximation using information from a plant's PRA and is intended as an
12 indicator of system performance. More accurate calculations using plant-specific PRAs or SPAR
13 models cannot be used to question the outcome of the PIs computed in accordance with this
14 guideline.

1   **Data Examples**

Mitigating System Performance Index

Quarter	1Q/05	2Q/05	3Q/05	4Q/05	1Q/06
Unavailability Index (UAI)	8.48E-08	1.00E-09	8.72E-08	1.00E-06	1.00E-07
Unreliability Index (URI)	1.42E-06	1.00E-09	3.55E-07	1.00E-06	1.00E-07
Performance Limit Exceeded	NO	NO	NO	YES	NO
Indicator Value (UAI + URI)	1.50E-06	2.00E-09	4.42E-07	PLE	2.00E-07

Threshold	
Green	$\leq$ 1.0E-06
White	> 1.0E-06 OR PLE= Yes
Yellow	> 1.0E-05
Red	> 1.0E-04

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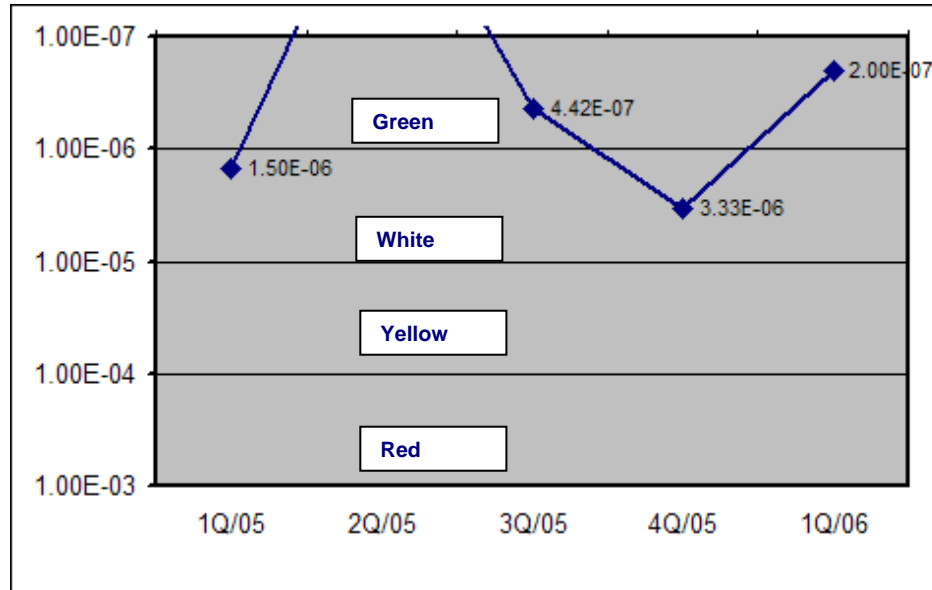
1   **2.3   BARRIER INTEGRITY CORNERSTONE**

2   The purpose of this cornerstone is to provide reasonable assurance that the physical design
3   barriers (fuel cladding, reactor coolant system, and containment) protect the public from
4   radionuclide releases caused by accidents or events. These barriers are an important element in
5   meeting the NRC mission of assuring adequate protection of public health and safety. The
6   performance indicators assist in monitoring the functionality of the fuel cladding and the reactor
7   coolant system. There is currently no performance indicator for the containment barrier. The
8   performance of this barrier is assured through the inspection program.
9
10   There are two performance indicators for this cornerstone:
11
12   • Reactor Coolant System (RCS) Specific Activity
13   • RCS Identified Leak Rate
14
15   REACTOR COOLANT SYSTEM (RCS) SPECIFIC ACTIVITY

16   **Purpose**

17   This indicator monitors the integrity of the fuel cladding, the first of the three barriers to prevent
18   the release of fission products. It measures the radioactivity in the RCS as an indication of
19   functionality of the cladding.
20
21   **Indicator Definition**

22   The maximum monthly RCS activity in micro-Curies per gram (µCi/gm) dose equivalent Iodine-
23   131 per the technical specifications, and expressed as a percentage of the technical specification
24   limit. Those plants whose technical specifications are based on micro-curies per gram (µCi/gm
25   total Iodine should use that measurement.
26
27   **Data Reporting Elements**

28   The following data are reported for each reactor unit:
29
30   • maximum calculated RCS activity for each unit, in micro-Curies per gram dose
31   equivalent Iodine-131, as required by technical specifications at steady state power,
32   for each month during the previous quarter (three values are reported).
33
34   • Technical Specification limit

1 **Calculation**

2 The indicator is calculated as follows:
3

4 $$\text{unit value} = \frac{\text{the maximum monthly value of calculated activity}}{\text{Technical Specification limit}} \times 100$$

5
6 **Definitions of Terms**

7 (Blank)
8
9 **Clarifying Notes**

10 This indicator is recorded monthly and reported quarterly.
11
12 The indicator is calculated using the same methodology, assumptions and conditions as for the
13 Technical Specification calculation. If more than one method can be used to meet Technical
14 Specifications, use the results of the method that was used at the time to satisfy the Technical
15 Specifications.
16
17 Unless otherwise defined by the licensee, steady state is defined as continuous operation for at
18 least three days at a power level that does not vary more than ±5 percent.
19
20 This indicator monitors the steady state integrity of the fuel-cladding barrier at power. Transient
21 spikes in RCS Specific Activity following power changes, shutdowns and scrams may not
22 provide a reliable indication of cladding integrity and should not be included in the monthly
23 maximum for this indicator.
24
25 Samples taken using technical specification methodology when shutdown are not reported.
26 However, samples taken using the technical specification methodology at steady state power
27 more frequently than required are to be reported. If in the entire month, plant conditions do not
28 require RCS activity to be calculated, the data field is left blank for that month and the status
29 "Final – N/A" is selected.
30
31 Licensees should use the most restrictive regulatory limit (e.g., technical specifications (TS) or
32 license condition). However, if the most restrictive regulatory limit is insufficient to assure plant
33 safety, then NRC Administrative Letter 98-10 applies, which states that imposition of
34 administrative controls is an acceptable short-term corrective action. When an administrative
35 control is in place as temporary measure to ensure that TS limits are met and to ensure public
36 health and safety (i.e., to ensure 10 CFR Part 100 dose limits are not exceeded), that
37 administrative limit should be used for this PI.
38
39
40

1   **Data Examples**

Reactor Coolant System Activity (RCSA)

	4/98	5/98	6/98	7/98	8/98	9/98	10/98	11/98	12/98	1/99	2/99	Prev. mth
Indicator, % of T.S. Limit	10	20	5	4	0.5	2	20	50	60	40	30	10
Max Activity µCi/gm I-131 Equival	0.1	0.2	0.05	0.04	0.005	0.02	0.2	0.5	0.6	0.4	0.3	0.1
T.S Limit	1	1	1	1	1	1	1	1	1	1	1	1
Thresholds	Green	≤ 50% T.S. limit										
	White	> 50% T.S limit										
	Yellow	>100% T.S. limit										

Reactor Coolant Activity

Month

4/98   5/98   6/98   7/98   8/98   9/98   10/98   11/98   12/98   1/99   2/99   Prev. mth

Indicator, % T.S. Limit

GREEN

WHITE

Note: Yellow>100% Tech. Spec Limit

2
3
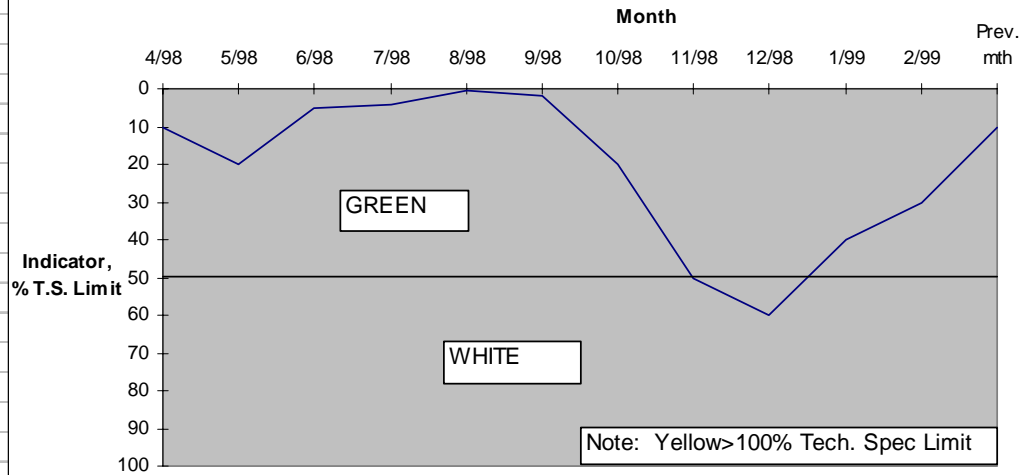
| 1 | **REACTOR COOLANT SYSTEM LEAKAGE** |

2 **Purpose**

3 This indicator monitors the integrity of the RCS pressure boundary, the second of the three
4 barriers to prevent the release of fission products. It measures RCS Identified Leakage as a
5 percentage of the technical specification allowable Identified Leakage to provide an indication of
6 RCS integrity.
7
8 **Indicator Definition**

9 The maximum RCS Identified Leakage in gallons per minute each month per the technical
10 specifications and expressed as a percentage of the technical specification limit.
11
12 **Data Reporting Elements**

13 The following data are required to be reported each quarter:
14
15 • The maximum RCS Identified Leakage calculation for each month of the previous
16 quarter (three values).
17 • Technical Specification limit
18
19 **Calculation**

20 The unit value for this indicator is calculated as follows:
21

22 $$\text{unit value} = \frac{\text{the maximum monthly value of identified leakage}}{\text{Technical Specification limiting value}} \times 100$$

23
24 **Definition of Terms**

25 RCS Identified Leakage as defined in Technical Specifications.
26
27 **Clarifying Notes**

28 This indicator is recorded monthly and reported quarterly.
29
30 Normal steam generator tube leakage is included in the unit value calculation if required by the
31 plant's Technical Specification definition of RCS identified leakage.
32
33 For those plants that do not have a Technical Specification limit on Identified Leakage, substitute
34 RCS Total Leakage in the Data Reporting Elements.
35
36 Any RCS leakage determination made in accordance with plant   Technical Specifications
37 methodology is included in the performance indicator calculation. If in the entire month, plant
38 conditions do not require RCS leakage to be calculated, the data field is left blank for that month
39 and the status "Final-N/A" is selected)
40

1   If the source and collection point of the leakage were unknown during the time period of the
2   leak, and the actual collection point was not a monitored tank or sump per the RCS Leakage
3   Calculation Procedure, then, for the purposes of this indicator, the leakage is not considered RCS
4   identified leakage and is not to be included in PI data. RCS leakage not captured under this
5   indicator may be evaluated in the inspection program.

1   **Data Examples**

Reactor Coolant System Identified Leakage (RCSL)											
	4/98	5/98	6/98	7/98	8/98	9/98	10/98	11/98	12/98	1/99	2/99	Prev. mth
Indicator %T.S. Value	60	40	10	70	50	60	40	30	30	20	20	20
Identified Leakage (gpm	6	4	1	7	5	6	4	3	3	2	2	2
TS Value (gpm)	10	10	10	10	10	10	10	10	10	10	10	10

Threshold	
Green	≤50% TS limit
White	>50% TS limit
Yellow	>100%TS limit

Data collected monthly, reported quarterly

Identifed RCS Leakage

Month

| 4/98 | 5/98 | 6/98 | 7/98 | 8/98 | 9/98 | 10/98 | 11/98 | 12/98 | 1/99 | 2/99 | Prev. mth |

Indicator, % of T. S. Limit

GREEN

WHITE

YELLOW
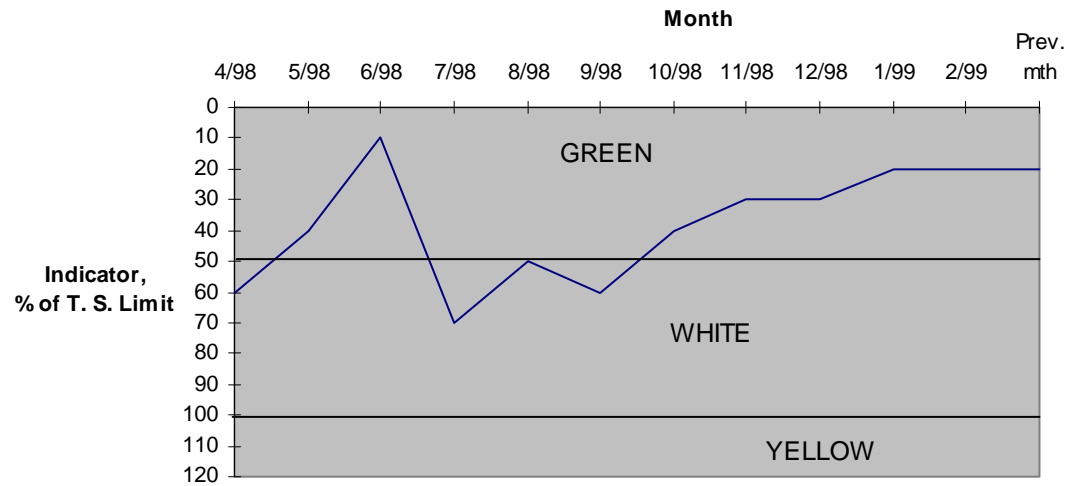
1 **2.4 EMERGENCY PREPAREDNESS CORNERSTONE**

2 The objective of this cornerstone is to ensure that the licensee is capable of implementing
3 adequate measures to protect the public health and safety during a radiological emergency.
4 Licensees maintain this capability through Emergency Response Organization (ERO)
5 participation in drills, exercises, actual events, training, and subsequent problem identification
6 and resolution.   The Emergency Preparedness performance indicators provide a quantitative
7 indication of the licensee's ability to implement adequate measures to protect the public health
8 and safety. These performance indicators create a licensee response band that allows NRC
9 oversight of Emergency Preparedness programs through a baseline inspection program.   These
10 performance indicators measure onsite Emergency Preparedness programs. Offsite programs are
11 evaluated by FEMA.
12
13 The protection of public health and safety is assured by a defense in depth philosophy that relies
14 on: safe reactor design and operation, the operation of mitigation features and systems, a multi-
15 layered barrier system to prevent fission product release, and emergency preparedness.
16
17 The Emergency Preparedness cornerstone performance indicators are:
18
19 • Drill/Exercise performance (DEP),
20 • Emergency Response Organization Drill Participation (ERO),
21 • Alert and Notification System Reliability (ANS)
22
23 **DRILL/EXERCISE PERFORMANCE**

24 **Purpose**

25 This indicator monitors timely and accurate licensee performance in drills and exercises when
26 presented with opportunities for classification of emergencies, notification of offsite authorities,
27 and development of protective action recommendations (PARs). It is the ratio, in percent, of
28 timely and accurate performance of those actions to total opportunities.
29
30 **Indicator Definition**

31 The percentage of all drill, exercise, and actual opportunities that were performed timely and
32 accurately by Key Positions, as defined in the ERO Drill Participation performance indicator,
33 during the previous eight quarters.
34
35 **Data Reporting Elements**

36 The following data are required to calculate this indicator:
37
38 • the number of drill, exercise, and actual event opportunities during the previous quarter.
39
40 • the number of drill, exercise, and actual event opportunities performed timely and accurately
41 during the previous quarter.
42
43 The indicator is calculated and reported quarterly. (See clarifying notes)

1   **Calculation**

2   The site average values for this indicator are calculated as follows:

3

4
$$\left[\frac{\text{\# of timely \& accurate classifications, notifications, \& PARs from DE \& AEs * during the previous 8 quarters}}{\text{The total opportunities to perform classifications, notifications \& PARs during the previous 8 quarters}}\right] \times 100$$

5

6   *DE & AEs = Drills, Exercises, and Actual Events
7

8   **Definition of Terms**

9   *Opportunities* should include multiple events during a single drill or exercise (if supported by the
10 scenario) or actual event, as follows:
11

12 •   each expected classification or upgrade in classification
13 •   each initial notification of an emergency class declaration
14 •   each initial notification of PARs or change to PARs
15 •   each PAR developed
16

17 *Timely* means:
18

19 •   classifications are made consistent with the goal of 15 minutes once available plant
20   parameters reach an Emergency Action Level (EAL)
21 •   PARs are made consistent with the goal of 15 minutes once data is available.
22 •   offsite notifications are initiated within 15 minutes of event classification and/or PAR
23   development (see clarifying notes)
24

25 *Accurate* means:
26

27 •   Classification and PAR appropriate to the event as specified by the approved plan and
28   implementing procedures (see clarifying notes)
29 •   Initial notification form completed appropriate to the event to include (see clarifying notes):
30   -   Class of emergency
31   -   EAL number
32   -   Description of emergency
33   -   Wind direction and speed
34   -   Whether offsite protective measures are necessary
35   -   Potentially affected population and areas
36   -   Whether a release is taking place
37   -   Date and time of declaration of emergency
38   -   Whether the event is a drill or actual event
39   -   Plant and/or unit as applicable
40

41 **Clarifying Notes**

42 While actual event opportunities are included in the performance indicator data, the NRC will
43 also inspect licensee response to all actual events.

1
2   As a minimum, actual emergency declarations and evaluated exercises are to be included in this
3   indicator. In addition, other simulated emergency events that the licensee formally assesses for
4   performance of classification, notification or PAR development may be included in this indicator
5   (opportunities cannot be removed from the indicator due to poor performance).
6
7   The following information provides additional clarification of the accuracy requirements
8   described above:
9

10   • It is understood that initial notification forms are negotiated with offsite authorities. If
11   the approved form does not include these elements, they need not be added. Alternately,
12   if the form includes elements in addition to these, those elements need not be assessed for
13   accuracy when determining the DEP PI. It is, however, expected that errors in such
14   additional elements would be critiqued and addressed through the corrective action
15   system.
16

17   • The description of the event causing the classification may be brief and need not include
18   all plant conditions. At some sites, the EAL number is the description.
19

20   • "Release" means a radiological release attributable to the emergency event.
21

22   • Minor discrepancies in the wind speed and direction provided on the emergency
23   notification form need not count as a missed notification opportunity provided the
24   discrepancy would not result in an incorrect PAR being provided.
25

26   The licensee shall identify, in advance, drills, exercises and other performance enhancing
27   experiences in which opportunities will be formally assessed, and shall be available for NRC
28   review. The licensee has the latitude to include opportunities in the PI statistics as long as the
29   drill (in whatever form) simulates the appropriate level of inter-facility interaction. The criteria
30   for suitable drills/performance enhancing experiences are provided under the ERO Drill
31   Participation PI clarifying notes.
32

33   If credit for an opportunity is given in the ERO Drill Participation performance indicator, then
34   that opportunity must be included in the drill/exercise performance indicator. For example, if the
35   communicator performing the entire notification during performance enhancing scenario is an
36   ERO member in a Key Position, then the notification may be considered as an opportunity and, if
37   so, participation credit awarded to the ERO member in the Key Position.
38

39   Performance statistics from operating shift simulator training evaluations may be included in this
40   indicator only when the scope requires classification. Classification, PAR notifications and
41   PARs may be included in this indicator if they are performed to the point of filling out the
42   appropriate forms and demonstrating sufficient knowledge to perform the actual notification.
43   However, there is no intent to disrupt ongoing operator qualification programs. Appropriate
44   operator training evolutions should be included in the indicator only when Emergency
45   Preparedness aspects are consistent with training goals. A successful PI opportunity is
46   determined by evaluating performance against program expectations.   Thus, if it is part of a pre-
47   established expectation to enhance the realism of the training environment by marking "actual"
48   on the notification forms, it should be considered a successful PI opportunity if a simulator crew

1   marks "actual" on the notification form. However, all notification forms must be marked
2   consistently, either "drill" or "actual" in accordance with the requirements of the licensee's
3   emergency preparedness program expectation. Not marking either drill or actual event
4   (regardless of expectations) shall be a failed opportunity.
5
6   Some licensees have specific arrangements with their State authorities that provide for different
7   notification requirements than those prescribed by the performance indicator, e.g., within one
8   hour, not 15 minutes. In these instances the licensee should determine success against the
9   specific state requirements.
10
11   For sites with multiple agencies to notify, the notification is considered to be initiated when
12   contact is made with the first agency to transmit the initial notification information.
13
14   Simulation of notification to offsite agencies is allowed. It is not expected that State/local
15   agencies be available to support all drills conducted by licensees. The drill should reasonably
16   simulate the contact and the participants should demonstrate their ability to use the equipment.
17
18   Classification is expected to be made promptly following indication that the conditions have
19   reached an emergency threshold in accordance with the licensee's EAL scheme. With respect to
20   classification of emergencies, the 15 minute goal is a reasonable period of time for assessing and
21   classifying an emergency once indications are available to control room operators that an EAL
22   has been exceeded. Allowing a delay in classifying an emergency up to 15 minutes will have
23   minimal impact upon the overall emergency response to protect the public health and safety.
24   The 15-minute goal should not be interpreted as providing a grace period in which a licensee
25   may attempt to restore plant conditions and avoid classifying the emergency.
26
27   If an event has occurred that resulted in an emergency classification where no EAL was
28   exceeded, the incorrect classification should be considered a missed opportunity. The subsequent
29   notification should be considered an opportunity and evaluated on its own merits.
30
31   During drill performance, the ERO may not always classify an event exactly the way that the
32   scenario specifies. This could be due to conservative decision making, Emergency Director
33   judgment call, or a simulator driven scenario that has the potential for multiple 'forks'. Situations
34   can arise in which assessment of classification opportunities is subjective due to deviation from
35   the expected scenario path. In such cases, evaluators should document the rationale supporting
36   their decision for eventual NRC inspection. Evaluators must determine if the classification was
37   appropriate to the event as presented to the participants and in accordance with the approved
38   emergency plan and implementing procedures.
39
40   If the expected classification level is missed because an EAL is not recognized within 15 minutes
41   of availability, but a subsequent EAL for the same classification level is subsequently
42   recognized, the subsequent classification is not an opportunity for DEP statistics. The reason
43   that the classification is not an opportunity is that the appropriate classification level was not
44   attained in a timely manner.
45
46   If a controller intervenes (e.g., coaching, prompting) with the performance of an individual to
47   make an independent and correct classification, notification, or PAR, then that DEP PI
48   opportunity shall be considered a failure.
49

1 Failure to appropriately classify an event counts as only one failure: This is because notification
2 of the classification, development of any PARs and PAR notification are subsequent actions to
3 classification. Similarly, if the same error occurs in follow-up notifications, it should only be
4 considered a missed opportunity on the initial notification form.
5 A Classification based on a downgrade from a previously existing higher classification is not
6 counted as an opportunity. It was not the intent to count downgrades as opportunities for the
7 DEP performance indicator. When a higher classification is reached in a drill, exercise or real
8 event it is probable that multiple EALs at equal or lower levels have also been exceeded. When
9 the reason for the highest classification is cleared, many of the lower conditions may still exist.
10 It is impractical to evaluate downgrades in classification from a timeliness and accuracy
11 standpoint. The notification of the downgrade should be handled as an update rather than a
12 formal opportunity for the performance indicator.
13
14 The notification associated with a PAR is counted separately: e. g., an event triggering a GE
15 classification would represent a total of 4 opportunities: 1 for classification of the GE, 1 for
16 notification of the GE to the State and/or local government authorities, 1 for development of a
17 PAR and 1 for notification of the PAR. All PAR notifications resulting in a Recommendation of
18 Evacuation or Shelter, whether default or not, should be counted as an opportunity for the
19 drill/exercise performance indicator.
20
21 If PARs at the SAE are in the site Emergency Plan they could be counted as opportunities.
22 However, this would only be appropriate where assessment and decision making is involved in
23 development of the PAR. Automatic PARs with little or no assessment required would not be an
24 appropriate contributor to the PI. PARs limited to livestock or crops and no PAR necessary
25 decisions are also not appropriate.
26
27 Dose assessment and PAR development are expected to be made promptly following indications
28 that the conditions have reached a threshold in accordance with the licensee's PAR scheme. The
29 15 minute goal from data availability is a reasonable period of time to develop or expand a PAR.
30 Plant conditions, meteorological data, field monitoring data, and/or radiation monitor data should
31 provide sufficient information to determine the need to change PARs. If radiation monitor
32 readings provide sufficient data for assessments, it is not appropriate to wait for field monitoring
33 to become available to confirm the need to expand the PAR. The 15 minute goal should not be
34 interpreted as providing a grace period in which the licensee may attempt to restore conditions
35 and avoid making the PAR recommendation.
36
37 If a licensee has identified in its scenario objectives that Protective Action Guidelines (PAGs)
38 will be exceeded beyond the 10 mile plume exposure pathway emergency planning zone (EPZ)
39 boundary, then this would constitute a PI opportunity. In addition, there is a DEP PI opportunity
40 associated with the timeliness of the notification of the PAR to offsite agencies. Essential to
41 understanding that these DEP PI opportunities exist is the need to realize that it is a regulatory
42 requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be
43 exceeded beyond the 10 mile plume exposure pathway EPZ. However, the licensee always has
44 the latitude to identify which DEP PI opportunities will be included in the PI statistics prior to
45 the exercise. Thus, a licensee may choose to not include a PAR beyond the 10-mile EPZ as a
46 DEP PI statistic due to its ad hoc nature.
47

1 If a licensee discovers after the fact (greater than 15 minutes) that an event or condition had
2 existed which exceeded an EAL, but no emergency had been declared and the EAL is no longer
3 exceeded at the time of discovery, the following applies:
4 • If the indication of the event was not available to the operator, the event should not be
5   evaluated for PI purposes.
6 • If the indication of the event was available to the operator but not recognized, it should be
7   considered an unsuccessful classification opportunity.
8 • In either case described above, notification should be performed in accordance with
9   NUREG-1022 and not be evaluated as a notification opportunity.
10

1   **Data Example**

Emergency Response Organization
Drill/Exercise Performance

							3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98
Successful Classifications, Notifications & PARs over qtr							0	0	11	11	0	8	10	0	23
Opportunities to Perform Classifications, Notifications, & PARs in qtr							0	0	12	12	0	12	12	0	24
Total # of succesful Classifications, Notifications, & PARs in 8 qtrs														40	63
Total # of opportunities to perform Classification, Notifications & PARs in 8 qtrs														48	72
														2Q/98	3Q/98
Indicator expressed as a percentage of Opportunities to perform,														83.3%	87.5%
Classifications, Communications & PARs															

2
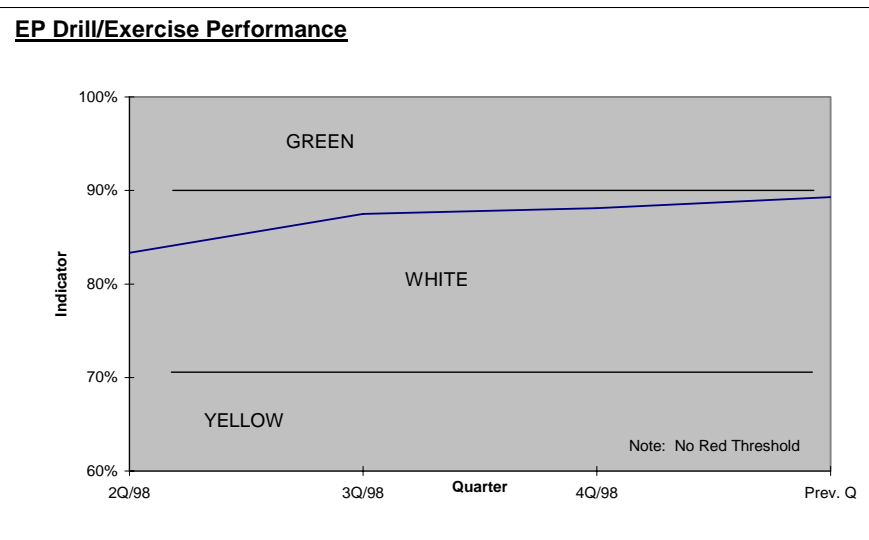
1 | **EMERGENCY RESPONSE ORGANIZATION DRILL PARTICIPATION**

2 **Purpose**

3 This indicator tracks the participation of ERO members assigned to fill Key Positions in
4 performance enhancing experiences, and through linkage to the DEP indicator ensures that the
5 risk significant aspects of classification, notification, and PAR development are evaluated and
6 included in the PI process. This indicator measures the percentage of ERO members assigned to
7 fill Key Positions who have participated recently in performance-enhancing experiences such as
8 drills, exercises, or in an actual event.
9
10 **Indicator Definition**

11 The percentage of ERO members assigned to fill Key Positions that have participated in a drill,
12 exercise, or actual event during the previous eight quarters, **as measured on the last calendar**
13 **day of the quarter.**
14
15 **Data Reporting Elements**

16 The following data are required to calculate this indicator and are reported:
17
18 • total number of ERO members assigned to fill Key Positions
19 • total number of ERO members assigned to fill Key Positions that have participated in a
20 drill, exercise, or actual event in the previous eight quarters
21
22 The indicator is calculated and reported quarterly, based on participation over the previous eight
23 quarters (see clarifying notes)
24
25 **Calculation**

26 The site indicator is calculated as follows:
27

28 $$\frac{\text{\# of ERO members assigned to Key Positions that have participated in drill, exercise or actual event the previous 8 qrts}}{\text{Total number of Key Positions assigned to ERO Members}} \times 100$$

29
30
31 **Definition of Terms**

32 Key Positions are defined below
33
34 • Control Room
35
36 • Shift Manager (Emergency Director) - Supervision of reactor operations, responsible
37 for classification, notification, and determination of protective action
38 recommendations
39
40 • Shift Communicator - provides initial offsite (state/local) notification
41

44

- Technical Support Center

    - Senior Manager - Management of plant operations/corporate resources
    - Key Operations Support
    - Key Radiological Controls - Radiological effluent and environs monitoring, assessment, and dose projections
    - Key TSC Communicator- provides offsite (state/local) notification
    - Key Technical Support

- Emergency Operations Facility

    - Senior Manager - Management of corporate resources
    - Key Protective Measures - Radiological effluent and environs monitoring, assessment, and dose projections
    - Key EOF Communicator- provides offsite (state/local) notification

- Operational Support Center

    - Key OSC Operations Manager
- Assigned: Those ERO personnel filling Key Positions listed on the licensee duty roster on the last day of the quarter of the reporting period.

Clarifying Notes

When the performance of Key Positions includes classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) statistics for participation of those Key Positions to contribute to ERO Drill Participation.

The licensee may designate drills as not contributing to DEP and, if the drill provides a performance enhancing experience as described herein, those Key Positions that do not involve classification, notification or PARs may be given credit for ERO Drill Participation. Additionally, the licensee may designate elements of the drills not contributing to DEP (e.g., classifications will not contribute but notifications will contribute to DEP.) In this case, the participation of all Key Positions, except those associated with the non-contributing elements, may contribute to ERO Drill Participation. The licensee must document such designations in advance of drill performance and make these records available for NRC inspection.

Evaluated simulator training evolutions that contribute to Drill/Exercise Performance indicator statistics may be considered as opportunities for ERO Drill Participation. The scenarios must at least contain a formally assessed classification and the results must be included in DEP statistics. However, there is no intent to disrupt ongoing operator qualification programs. Appropriate operator training evolutions should be included in this indicator only when Emergency Preparedness aspects are consistent with training goals.

If an ERO member filling a Key Position has participated in more than one drill during the eight quarter evaluation period, the most recent participation should be used in the Indicator statistics.

1 If a change occurs in the number of ERO members filling Key Positions, this change should be
2 reflected in both the numerator and denominator of the indicator calculation.
3
4 If a person is assigned to more than one Key Position, it is expected that the person be counted in
5 the denominator for each position and in the numerator only for drill participation that addresses
6 each position. Where the skill set is similar, a single drill might be counted as participation in
7 both positions.
8
9 Assigning a single member to multiple Key Positions and then only counting the performance for
10 one Key Position could mask the ability or proficiency of the remaining Key Positions. The
11 concern is that an ERO member having multiple Key Positions may never have a performance
12 enhancing experience for all of them, yet credit for participation will be given when any one of
13 the multiple Key Positions is performed; particularly, if more than one ERO position is assigned
14 to perform the same Key Position.
15
16 ERO participation should be counted for each Key Position, even when multiple Key Positions
17 are assigned to the same ERO member. In the case where a utility has assigned two or more Key
18 Positions to a single ERO member, each Key Position must be counted in the denominator for
19 that ERO member and credit given in the numerator when the ERO member performs each Key
20 Position.
21
22 Similarly, ERO members need not individually perform an opportunity of classification,
23 notification, or PAR development in order to receive ERO Drill Participation credit. The
24 evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response
25 Organization. ERO members may receive credit for the drill if their participation is a meaningful
26 opportunity to gain proficiency in their ERO function.
27
28 When an ERO member changes from one Key Position to a different Key Position with a skill
29 set similar to the old one, the last drill/exercise participation may count. If the skill set for the
30 new position is significantly different from the old position then the previous participation would
31 not count.
32
33 Participation may be as a participant, mentor, coach, evaluator, or controller, but not as an
34 observer. Multiple assignees to a given Key Position could take credit for the same drill if their
35 participation is a meaningful opportunity to gain proficiency.
36
37 The meaning of "drills" in this usage is intended to include performance enhancing experiences
38 (exercises, functional drills, simulator drills, table top drills, mini drills, etc.) that reasonably
39 simulate the interactions between appropriate centers and/or individuals that would be expected
40 to occur during emergencies. For example, control room interaction with offsite agencies could
41 be simulated by instructors or OSC interaction could be simulated by a control cell simulating
42 the TSC functions, and damage control teams.
43
44 In general, a drill does not have to include all ERO facilities to be counted in this indicator. A
45 drill is of adequate scope if it reasonably simulates the interaction between one or more of the
46 following facilities, as would be expected to occur during emergencies:
47
48   •   the control room,
49   •   the Technical Support Center (TSC),

1   •   the Operations Support Center,
2   •   the Emergency Operations Facility (EOF),
3   •   field monitoring teams,
4   •   damage control teams, and
5   •   offsite governmental authorities.
6
7 The licensee need not develop new scenarios for each drill or each team. However, it is expected
8 that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a
9 performance enhancing experience. A reasonable level of confidentiality means that some
10 scenario information could be inadvertently revealed and the drill remain a valid performance
11 enhancing experience. It is expected that the licensee will remove from drill performance
12 statistics any opportunities considered to be compromised. There are many processes for the
13 maintenance of scenario confidentiality that are generally successful. Examples may include
14 confidentiality statements on the signed attendance sheets and spoken admonitions by drill
15 controllers. Examples of practices that may challenge scenario confidentiality include drill
16 controllers or evaluators or mentors, who have scenario knowledge becoming participants in
17 subsequent uses of the same scenarios and use of scenario reviewers as participants.
18
19 All individuals qualified to fill the Control Room Shift Manager/ Emergency Director position
20 that actually might fill the position should be included in this indicator.
21
22 The communicator is the Key Position that fills out the notification form, seeks approval and
23 usually communicates the information to off site agencies. Performance of these duties is
24 assessed for accuracy and timeliness and contributes to the DEP PI. Senior managers who do not
25 perform these duties should not be considered communicators even though they approve the
26 form and may supervise the work of the communicator. However, there are cases where the
27 senior manager actually collects the data for the form, fills it out, approves it and then
28 communicates it or hands it off to a phone talker. Where this is the case, the senior manager is
29 also the communicator and the phone talker need not be tracked. The communicator is not
30 expected to be just a phone talker who is not tasked with filling out the form. There is no intent
31 to track a large number of shift communicators or personnel who are just phone talkers.
32
33
34

1   **Data Example**

Emergency Response Organization (ERO) Participation					2Q/98	3Q/98	4Q/98	Prev. Q	
Total number of Key ERO personnel					56	56	64	64	
Number of Key personnel participating in drill/event in 8 qtrs					48	52	54	53	
					2Q/98	3Q/98	4Q/98	Prev. Q	
Indicator percentage of Key ERO personnel participating in a drill in 8 qtrs					86%	93%	84%	83%	

Thresholds	
Green	≥80%
White	<80%
Yellow	<60%
No Red Threshold	

ERO Key Personnel Participation

GREEN

Indicator

WHITE

YELLOW   Note: No Red threshold

100%
90%
80%
70%
60%
50%

2Q/98   3Q/98   4Q/98   Prev. Q

Quarter

2
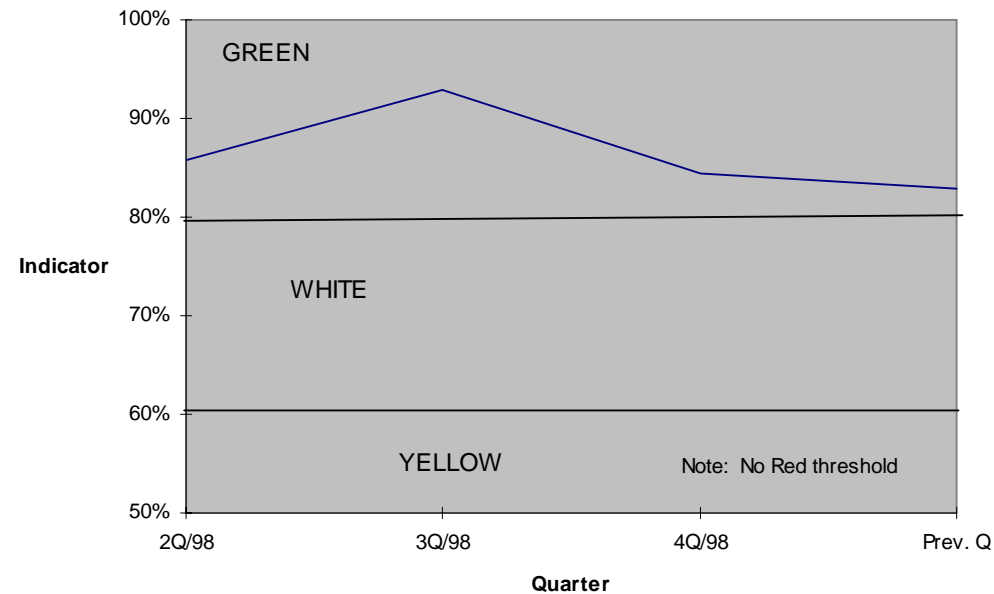
1 | **ALERT AND NOTIFICATION SYSTEM RELIABILITY**

2 **Purpose**

3 This indicator monitors the reliability of the offsite Alert and Notification System (ANS), a
4 critical link for alerting and notifying the public of the need to take protective actions. It
5 provides the percentage of the sirens that are capable of performing their safety function based
6 on regularly scheduled tests.
7
8 **Indicator Definition**

9 The percentage of ANS sirens that are capable of performing their function, as measured by
10 periodic siren testing in the previous 12 months.
11
12 Periodic tests are the regularly scheduled tests (documented in the licensee's test plan or
13 guidelines) that are conducted to actually test the ability of the sirens to perform their function
14 (e.g., silent, growl, siren sound test). Tests performed for maintenance purposes should not be
15 counted in the performance indicator database.
16
17 **Data Reporting Elements**

18 The following data are reported: (see clarifying notes)
19
20 • the total number of ANS siren-tests during the previous quarter
21 • the number of successful ANS siren-tests during the previous quarter
22
23 **Calculation**

24 The site value for this indicator is calculated as follows:
25

26
$$\frac{\#\ of\ succesful\ siren\ \text{-}\ tests\ in\ the\ previous\ 4\ qtrs}{total\ number\ of\ siren\ \text{-}\ tests\ in\ the\ previous\ 4\ qtrs} \times 100$$

27
28 **Definition of Terms**

29 *Siren-Tests:* the number of sirens times the number of times they are tested. For example, if 100
30 sirens are tested 3 times in the quarter, there are 300 siren-tests.
31
32 *Successful siren-tests* are the sum of sirens that performed their function when tested. For
33 example, if 100 sirens are tested three times in the quarter and the results of the three tests are:
34 first test, 90 performed their function; second test, 100 performed their function; third test, 80
35 performed their function. There were 270 successful siren-tests.

36 **Clarifying Notes**

37 The purpose of the ANS PI is to provide a uniform industry reporting approach and is not
38 intended to replace the FEMA Alert and Notification reporting requirement at this time.
39

1   For those sites that do not have sirens, the performance of the licensee's alert and notification
2   system will be evaluated through the NRC baseline inspection program. A site that does not
3   have sirens does not report data for this indicator.
4
5   If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test
6   is conducted, then it counts as both a siren test and a siren failure. Regularly scheduled tests
7   missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or
8   repair) should be considered non opportunities. The failure to perform a regularly scheduled test
9   should be noted in the comment field.
10
11
12   For plants where scheduled siren tests are initiated by local or state governments, if a scheduled
13   test is not performed either intentionally or accidentally, the missed test is not considered as valid
14   test opportunities. Missed test occurrences should be entered in the plant's corrective action
15   program.
16
17   If a siren failure is determined to be due only to testing equipment, and subsequent testing shows
18   the siren to be operable (verified by telemetry or simultaneous local verification) without any
19   corrective action having been performed, the siren test should be considered a success.
20   Maintenance records should be complete enough to support such determinations and validation
21   during NRC inspection.
22
23   A licensee may change ANS test methodology at any time consistent with regulatory guidance.
24   For the purposes of this performance indicator, only the testing methodology in effect on the first
25   day of the quarter shall be used for that quarter. Neither successes nor failures beyond the testing
26   methodology at the beginning of the quarter will be counted in the PI. (No actual siren activation
27   data results shall be included in licensees' ANS PI data.) Any change in test methodology shall
28   be reported as part of the ANS Reliability Performance Indicator effective the start of the next
29   quarterly reporting period. Changes should be noted in the comment field.
30
31   Siren systems may be designed with equipment redundancy, multiple signals or feedback
32   capability. It may be possible for sirens to be activated from multiple control stations or signals.
33   If the use of redundant control stations or multiple signals is in approved procedures and is part
34   of the actual system activation process, then activation from either control station or any signal
35   should be considered a success. A failure of both systems would only be considered one failure,
36   whereas the success of either system would be considered a success. If the redundant control
37   station is not normally attended, requires setup or initialization, it may not be considered as part
38   of the regularly scheduled test. Specifically, if the station is only made ready for the purpose of
39   siren tests it should not be considered as part of the regularly scheduled test.
40
41   If a siren is out of service for scheduled planned refurbishment or overhaul maintenance
42   performed in accordance with an established program, or for scheduled equipment upgrades, the
43   siren need not be counted as a siren test or a siren failure. However, sirens that are out of service
44   due to unplanned corrective maintenance would continue to be counted as failures. Unplanned
45   corrective maintenance is a measure of program reliability. The exclusion of a siren due to
46   temporary unavailability during planned maintenance/upgrade activities is acceptable due to the
47   level of control placed on scheduled maintenance/upgrade activities.   It is not the intent to create
48   a disincentive to performing maintenance/upgrades to ensure the ANS performs at its peak
49   reliability.

1
2   As part of a refurbishment or overhaul plan, it is expected that each utility would communicate
3   to the appropriate state and/or local agencies the specific sirens to be worked and ensure that a
4   functioning backup method of public alerting would be in-place. The acceptable time frame for
5   allowing a siren to remain out of service for system refurbishment or overhaul maintenance
6   should be coordinated with the state and local agencies. Based on the impact to their
7   organization, these time frames should be specified in upgrade or system improvement
8   implementation plans and/or maintenance procedures. Deviations from these plans and/or
9   procedures would constitute unplanned unavailability and would be included in the PI.
10
11   Siren testing conducted at redundant control stations, such as county EOCs that are staffed
12   during an emergency by an individual capable of activating the sirens, may be credited provided
13   the redundant control station is in an approved facility as documented in the FEMA ANS design
14   report.

1   **Data Example**

Alert & Notification System Reliability							
Quarter	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
Number of succesful siren-tests in the qtr	47	48	49	49	49	54	52
Total number of sirens tested in the qtr	50	50	50	50	50	55	55
Number of successful siren-tests over 4 qtrs				193	195	201	204
Total number of sirens tested over 4 qtrs				200	200	205	210
				2Q/98	3Q/98	4Q/98	Prev. Q
Indicator expressed as a percentage of sirens				96.5%	97.5%	98.0%	97.1%
Thresholds							
Green	≥94%						
White	<94%						
Yellow	<90%						
Red							

ANS Reliability

2
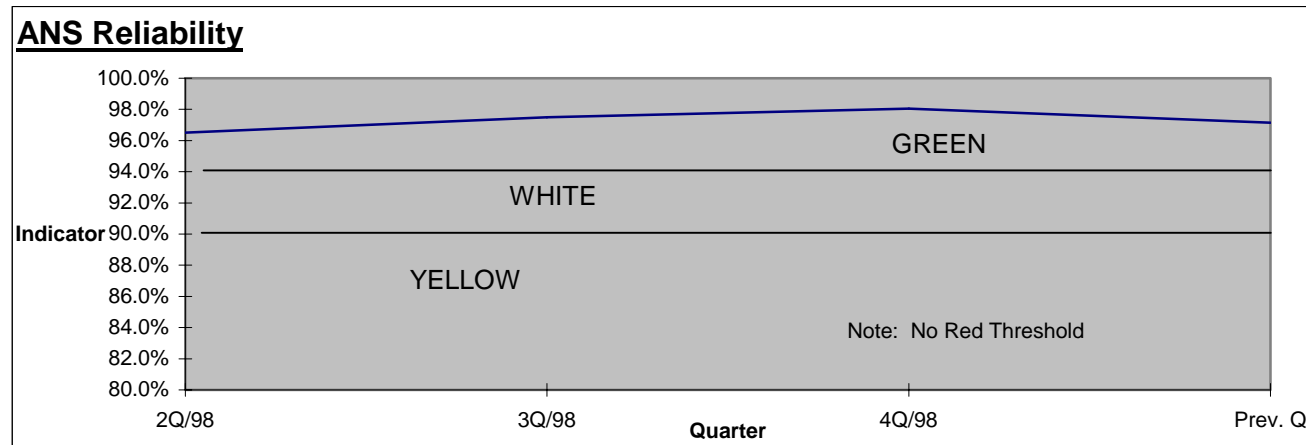
1   **2.5   OCCUPATIONAL RADIATION SAFETY CORNERSTONE**

2   The objectives of this cornerstone are to:

3

4   (1)   keep occupational dose to individual workers below the limits specified in
5   10 CFR Part 20 Subpart C; and

6

7   (2)   use, to the extent practical, procedures and engineering controls based upon sound
8   radiation protection principles to achieve occupational doses that are as low as is
9   reasonably achievable (ALARA) as specified in 10 CFR 20.1101(b).

10

11   There is one indicator for this cornerstone:

12

13   •   Occupational Exposure Control Effectiveness

14

15 | **OCCUPATIONAL EXPOSURE CONTROL EFFECTIVENESS** |
| --- |

16   **Purpose**

17   The purpose of this performance indicator is to address the first objective of the occupational
18   radiation safety cornerstone. The indicator monitors the control of access to and work activities
19   within radiologically-significant areas of the plant and occurrences involving degradation or
20   failure of radiation safety barriers that result in readily-identifiable unintended dose.

21

22   The indicator includes dose-rate and dose criteria that are risk-informed, in that the indicator
23   encompasses events that might represent a substantial potential for exposure in excess of
24   regulatory limits. The performance indicator also is considered "leading" because the indicator:

25

26   •   encompasses less-significant occurrences that represent precursors to events that might
27   represent a substantial potential for exposure in excess of regulatory limits, based on industry
28   experience; and

29

30   •   employs dose criteria that are set at small fractions of applicable dose limits (e.g., the criteria
31   are generally at or below the levels at which dose monitoring is required in regulation).

32

33   **Indicator Definition**

34   The performance indicator for this cornerstone is the sum of the following:

35

36   •   Technical specification high radiation area (>1 rem per hour) occurrences
37   •   Very high radiation area occurrences
38   •   Unintended exposure occurrences

39

1   **Data Reporting Elements**

2   The data listed below are reported for each site. For multiple unit sites, an occurrence at one unit
3   is reported identically as an input for each unit. However, the occurrence is only counted once
4   against the site-wide threshold value.
5
6   • The number of technical specification high radiation area (>1 rem per hour)
7   occurrences during the previous quarter
8   • The number of very high radiation area occurrences during the previous quarter
9   • The number of unintended exposure occurrences during the previous quarter
10
11   **Calculation**

12   The indicator is determined by summing the reported number of occurrences for each of the
13   three data elements during the previous 4 quarters.
14
15   **Definition of Terms**

16   *Technical Specification High Radiation Area (>1 rem per hour) Occurrence* - A
17   nonconformance (or concurrent[4] nonconformances) with technical specifications[5] or comparable
18   requirements in 10 CFR 20[6] applicable to technical specification high radiation areas (>1 rem per
19   hour) that results in the loss of radiological control over access or work activities within the
20   respective high-radiation area (>1 rem per hour). For high radiation areas (>1 rem per hour), this
21   PI does not include nonconformance with licensee-initiated controls that are beyond what is
22   required by technical specifications and the comparable provisions in 10 CFR Part 20.
23
24   Technical Specification high radiation areas, commonly referred to as locked high radiation
25   areas, includes any area, accessible to individuals, in which radiation levels from radiation
26   sources external to the body are in excess of 1 rem (10 mSv) per 1 hour at 30 centimeters from
27   the radiation source or 30 centimeters from any surface that the radiation penetrates, and
28   excludes very high radiation areas. Technical specification high radiation areas, in which
29   radiation levels from radiation sources external to the body are less than or equal to 1 rem (10
30   mSv) per 1 hour at 30 centimeters from the radiation source or 30 centimeters from any surface
31   that the radiation penetrates, are excluded from this performance indicator.
32
33   • "Radiological control over access to technical specification high radiation areas" refers to
34   measures that provide assurance that inadvertent entry[7] into the technical specification high
35   radiation areas by unauthorized personnel will be prevented.
36   • "Radiological control over work activities" refers to measures that provide assurance that
37   dose to workers performing tasks in the area is monitored and controlled.
38

---

[4] "Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe.
[5] Or comparable provisions in licensee procedures if the technical specifications do not include provisions for high
radiation areas.
[6] Includes 10 CFR 20, §20.1601(a), (b), (c), and (d) and §20.1902(b).
[7] In reference to application of the performance indicator definition in evaluating physical barriers, the term
"inadvertent entry" means that the physical barrier can not be easily circumvented (i.e., an individual who
incorrectly assumes, for whatever reason, that he or she is authorized to enter the area, is unlikely to disregard, and
circumvent, the barrier). The barriers used to control access to technical specification high radiation areas should
provide reasonable assurance that they secure the area against unauthorized access. (FAQ 368)

1 Examples of occurrences that would be counted against this indicator include:
2 • Failure to post an area as required by technical specifications,
3 • Failure to secure an area against unauthorized access,
4 • Failure to provide a means of personnel dose monitoring or control required by technical
5   specifications,
6 • Failure to maintain administrative control over a key to a barrier lock as required by technical
7   specifications, or
8 • An occurrence involving unauthorized or unmonitored entry into an area,
9 • Nonconformance with a requirement of an RWP (as specified in the licensee's technical
10   specifications) that results in a loss of control of access to or work within a technical
11   specification high radiation area.
12
13 Examples of occurrences that are not counted include the following:
14 • Situations involving areas in which dose rates are less than or equal to 1 rem per hour,
15 • Occurrences associated with isolated equipment failures. This might include, for example,
16   discovery of a burnt-out light, where flashing lights are used as a technical specification
17   control for access, or a failure of a lock, hinge, or mounting bolts, when a barrier is checked
18   or tested.[8]
19 • Nonconformance with an RWP requirement that does not result in a loss of control of access
20   to or work within a technical specification high radiation area (e.g., signing in on the wrong
21   RWP, but having received the prejob brief and implemented all of the access work control
22   requirements of the correct RWP).
23
24 *Very High Radiation Area Occurrence* - A nonconformance (or concurrent nonconformances)
25 with 10 CFR 20 and licensee procedural requirements that results in the loss of radiological
26 control over access to or work activities within a very high radiation area. "Very high radiation
27 area" is defined as any area accessible to individuals, in which radiation levels from radiation
28 sources external to the body could result in an individual receiving an absorbed dose in excess of
29 500 rads (5 grays) in 1 hour at 1 meter from a radiation source or 1 meter from any surface that
30 the radiation penetrates
31
32 • "Radiological control over access to very high radiation areas" refers to measures to ensure
33   that an individual is not able to gain unauthorized or inadvertent access to very high radiation
34   areas.
35 • "Radiological control over work activities" refers to measures that provide assurance that
36   dose to workers performing tasks in the area is monitored and controlled.
37
38 *Unintended Exposure Occurrence* - A single occurrence of degradation or failure of one or more
39 radiation safety barriers that results in unintended occupational exposure(s), as defined below.
40
41 Following are examples of an occurrence of degradation or failure of a radiation safety barrier
42 included within this indicator:
43
44 • failure to identify and post a radiological area
45 • failure to implement required physical controls over access to a radiological area

---

[8] Presuming that the equipment is subject to a routine inspection or preventative maintenance program, that the occurrence was indeed isolated, and that the causal condition was corrected promptly upon identification.

1   •   failure to survey and identify radiological conditions
2   •   failure to train or instruct workers on radiological conditions and radiological work controls
3   •   failure to implement radiological work controls (e.g., as part of a radiation work permit)
4

5 An occurrence of the degradation or failure of one or more radiation safety barriers is only
6 counted under this indicator if the occurrence resulted in unintended occupational exposure(s)
7 equal to or exceeding any of the dose criteria specified in the table below. The dose criteria were
8 selected to serve as "screening criteria," only for the purpose of determining whether an
9 occurrence of degradation or failure of a radiation safety barrier should be counted under this
10 indicator. The dose criteria should not be taken to represent levels of dose that are "risk-
11 significant." In fact, the dose criteria selected for screening purposes in this indicator are
12 generally at or below dose levels that are required by regulation to be monitored or to be
13 routinely reported to the NRC as occupational dose records.
14

15   **Table: Dose Values Used as Screening Criteria to Identify an Unintended Exposure**
16   **Occurrence in the Occupational Exposure Control Effectiveness PI**
17

2% of the stochastic limit in 10 CFR 20.1201 on total effective dose equivalent. The 2% value is 0.1 rem.	
10 % of the non-stochastic limits in 10 CFR 20.1201. The 10% values are as follows:	
5 rem	the sum of the deep-dose equivalent and the committed dose equivalent to any individual organ or tissue
1.5 rem	the lens dose equivalent to the lens of the eye
5 rem	the shallow-dose equivalent to the skin or any extremity, other than dose received from a discrete radioactive particle (DRP)[9]
20% of the limits in 10 CFR 20.1207 and 20.1208 on dose to minors and declared pregnant women. The 20% value is 0.1 rem.	

18
19 "Unintended exposure" refers to exposure that results in dose in excess of the administrative
20 guideline(s) set by a licensee as part of their radiological controls for access or entry into a
21 radiological area. Administrative dose guidelines may be established
22
23   •   within radiation work permits, procedures, or other documents,
24   •   via the use of alarm setpoints for personnel dose monitoring devices, or
25   •   by other means, as specified by the licensee.
26

---

[9] Controls established for DRPs are intended to minimize the possibility of exposures that could result in the SDE dose limit being exceeded, not to maintain the exposure to some intended SDE dose. Therefore, for the purpose of this PI, any DRP exposure is considered "unintended" and is a reportable PI event if it results (by itself, or added to previous "uniform" SDE exposures) in an SDE in excess of the regulatory limit in 20.1201(a)(2)(ii).

1 It is incumbent upon the licensee to specify the method(s) being used to administratively control
2 dose. An administrative dose guideline set by the licensee is not a regulatory limit and does not,
3 in itself, constitute a regulatory requirement. A revision to an administrative dose guideline(s)
4 during job performance is acceptable (with regard to this PI) if conducted in accordance with
5 plant procedures or programs.
6
7 If a specific type of exposure was not anticipated or specifically included as part of job planning
8 or controls, the full amount of the dose resulting from that type of exposure should be considered
9 as "unintended" in making a comparison with the respective criteria in the PI. For example, this
10 might include Committed Effective Dose Equivalent (CEDE), Committed Dose Equivalent
11 (CDE), or Shallow Dose Equivalent (SDE).
12
13
14 **<u>Clarifying Notes</u>**

15 An occurrence (or concurrent occurrences) that potentially meet the definition of more than one
16 element of the performance indicator will only be counted once. In other words, an occurrence
17 (or concurrent occurrences) will not be double-counted (or triple-counted) against the
18 performance indicator. If two or more individuals are exposed in a single occurrence, the
19 occurrence is only counted once.
20
21 Radiography work conducted at a plant under another licensee's 10 CFR Part 34 license is
22 generally outside the scope of this PI. However, if a Part 50 licensee opts to establish additional
23 radiological controls under its own program consistent with technical specifications or
24 comparable provisions in 10 CFR Part 20, then a non-conformance with such additional controls
25 or unintended dose resulting from the non-conformance shall be evaluated under the criteria in
26 the PI.
27
28

1   **Data Example**

Occupational Exposure Control Effectiveness

Quarter	3Q/95	4Q/95	1Q/96	2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qrtr
Number of technical specification high radiation occurrences during the quarter	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0
Number of very high radiation area occurrences during the quarter	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0
Number of unintended exposure occurrences during the quarter	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Reporting Quarter				2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qrtr
Total # of occurrences in the previous 4 qtrs				4	3	3	1	1	2	2	1	1	0	1	1

Thresholds	
Green	≤2
White	>2
Yellow	>5
No Red Threshold	

Occupational Exposure Control

2
3
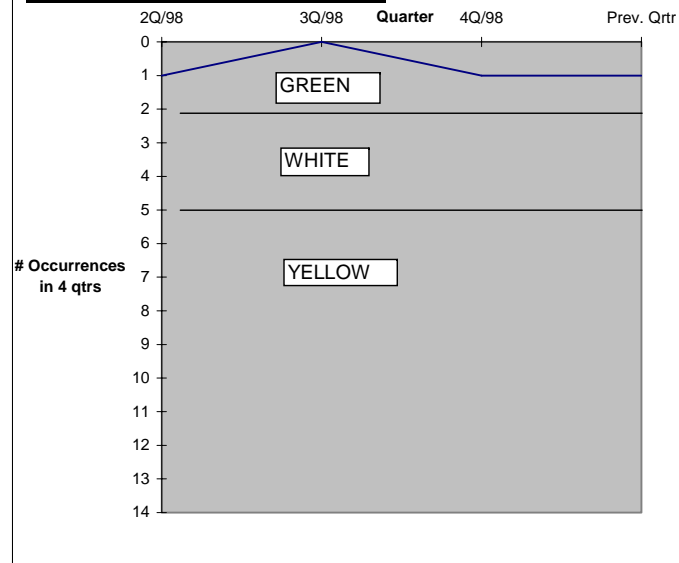
1   **2.6   PUBLIC RADIATION SAFETY CORNERSTONE**

2 | **RETS/ODCM RADIOLOGICAL EFFLUENT OCCURRENCE** |
     | --- |

3   **Purpose**

4   To assess the performance of the radiological effluent control program.

5

6   **Indicator Definition**

7   Radiological effluent release occurrences per site that exceed the values listed below:

8

Radiological effluent releases in excess of the following values:		
Liquid Effluents	Whole Body	1.5 mrem/qtr
	Organ	5 mrem/qtr
Gaseous Effluents	Gamma Dose	5 mrads/qtr
	Beta Dose	10 mrads/qtr
	Organ Doses from I-131, I-133, H-3 & Particulates	7.5 mrems/qtr

9
10   Note:
11   (1) Values are derived from the Radiological Effluent Technical Specifications (RETS) or
12   similar reporting provisions in the Offsite Dose Calculation Manual (ODCM), if applicable
13   RETS have been moved to the ODCM in accordance with Generic Letter 89-01.
14   (2) The dose values are applied on a per reactor unit basis in accordance with the RETS/ODCM.
15   (3) For multiple unit sites, allocation of dose on a per reactor unit basis from releases made via
16   common discharge points is to be calculated in accordance with the methodology specified in
17   the ODCM.
18
19   **Data Reporting Elements**

20   Number of RETS/ODCM Radiological Effluent Occurrences each quarter involving assessed
21   dose in excess of the indicator effluent values.
22
23   **Calculation**

24   Number of RETS/ODCM Radiological Effluent Occurrences per site in the previous four
25   quarters.
26
27   **Definition of Terms**

28   A RETS/ODCM Radiological Effluent Occurrence is defined as a release that exceeds any or all
29   of the five identified values outlined in the above table. These are the whole body and organ
30   dose values for liquid effluents and the gamma dose, beta dose, and organ dose values for
31   gaseous effluents.
32

1 **Clarifying Notes**

2 The following conditions do not count against the RETS/ODCM Radiological Effluent
3 Occurrence:
4
5 • Liquid or gaseous monitor operability issues
6
7 • Liquid or gaseous releases in excess of RETS/ODCM concentration or instantaneous
8   dose-rate values
9
10 • Liquid or gaseous releases without treatment but that do not exceed values in the table
11
12 Not all effluent sample (e.g., composite sample analysis) results are required to be finalized at
13 the time of submitting the quarterly PI reports. Therefore, the reports should be based upon the
14 best-available data. If subsequently available data indicates that the number of occurrences for
15 this PI is different than that reported, then the report should be revised, along with an explanation
16 regarding the basis for the revision.
17
18
19
20

1   **Data Example**

RESTS/ODCM Radiological Effluent Indicator					3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
Quarter					3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
Number of RETS/ODCM occurrences in the qtr					1	0	0	1	0	0	1
								2Q/98	3Q/98	4Q/98	Prev. Q
Number of RETS/ODCM occurrences in the previous 4 qtrs								2	1	1	2

RETS/ODCM Effluent Occurrences
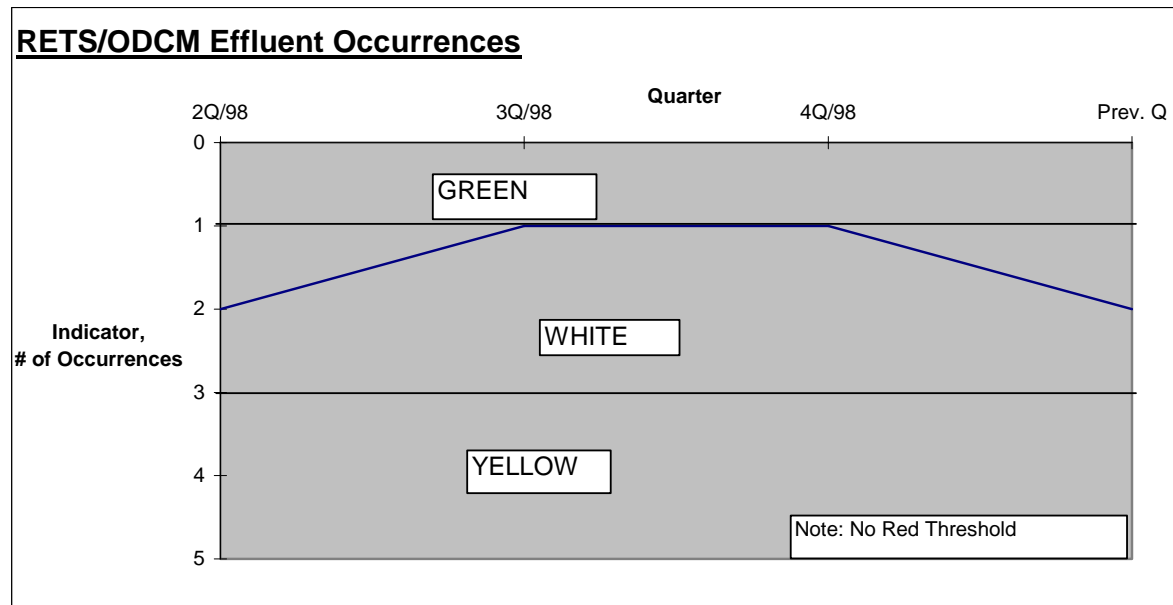
2

1
2
3
4   [This page intentionally left blank.]

1 **2.7   PHYSICAL PROTECTION CORNERSTONE**

2   Performance indicators for this cornerstone were selected to provide baseline and trend
3   information needed to evaluate each licensee's physical protection and access authorization
4   systems. The regulatory purpose is to provide high assurance that these systems will function to
5   protect against the design basis threat of radiological sabotage as defined in 10 CFR Part 73. As
6   a surrogate to any engineered physical security protection system, posted security officers
7   provide compensation when a portion of the system is unavailable to perform its intended
8   function. The performance indicator value is not an indication that the protection afforded by the
9   plant's physical security organization is less than required by the regulatory requirements.
10
11   An effective access authorization (AA) system minimizes the potential for an internal threat.
12   Basic elements of this program are the personnel screening program, the fitness-for-duty (FFD)
13   program and the continual behavior observation program (referred to as CBOP). When there has
14   been a programmatic failure or significant degradation in the AA system, the licensee is required
15   to take corrective action and report the event to the regulator. These reportable events are the
16   basis for the performance indicators (PI) that are used to monitor program effectiveness.
17
18   There is one performance indicator for the physical protection system, and two indicators for
19   access authorization. The performance indicators are assessed against established thresholds
20   using the data and methodology as established in this guideline. The NRC baseline inspections
21   will validate and verify the testing requirements for each system to assure performance standards
22   and testing periodicity are appropriate to provide valid data.
23
24   Performance Indicators:
25   The three physical protection performance indicators are:
26   1. Protected Area Security Equipment Performance Index,
27   2. Personnel Screening Program Performance, and
28   3. Fitness-for-Duty (FFD)/Personnel Reliability Program Performance.
29
30   The first indicator serves as a measure of a plant's ability to maintain equipment—to be available
31   to perform its intended function. When compensatory measures are employed because a
32   segment of equipment is unavailable—not adequately performing its intended function, there is
33   no security vulnerability but there is an indication that something needs to be fixed. The PI
34   provides trend indications for evaluation of the effectiveness of the maintenance process, and
35   also provides a method of monitoring equipment degradation as a result of aging that might
36   adversely impact reliability. Maintenance considerations for protected area and vital area portals
37   are appropriately and sufficiently covered by the inspection program.
38
39   The remaining two indicators measure significant programmatic deficiencies in the access and
40   trustworthiness programs. These programs verify that persons granted unescorted access to the
41   protected area have satisfactorily completed personal screening and, as a result, are considered to
42   be trustworthy and reliable. Each indicator is based on the number of reportable events, required
43   by regulation, that reveal significant problems in the management and operation of the licensee's
44   access authorization or fitness-for-duty programs.
45

1 PROTECTED AREA (PA) SECURITY EQUIPMENT PERFORMANCE INDEX

2 **Purpose:**

3 Operability of the PA security system is necessary to detect and assess safeguards events and to
4 provide the first line of the defense-in-depth physical protection of the plant perimeter. In the
5 event of an attempted encroachment, the intrusion detection system identifies the existence of the
6 threat, the barriers provide a delay to the person(s) posing the threat and the alarm assessment
7 system is used to determine the magnitude of the threat. The PI is used to monitor the
8 unavailability of PA intrusion detection systems and alarm assessment systems to perform their
9 intended function.
10
11 **Indicator Definition:**

12 PA Security equipment performance is measured by an index that compares the amount of the
13 time CCTVs and IDS are unavailable, as measured by compensatory hours, to the total hours in
14 the period. A normalization factor is used to take into account site variability in the size and
15 complexity of the systems.
16
17 **Data Reporting Elements:**

18 Report the following site data for the previous quarter for each unit:
19
20 • Compensatory hours, CCTVs: The hours (expressed to the nearest tenth of an hour)
21 expended in posting a security officer as required compensation for camera(s) unavailability
22 because of degradation or defects.

23 • Compensatory hours, IDS: The hours (expressed to the nearest tenth of an hour) expended in
24 posting a security officer as required compensation for IDS unavailability because of
25 degradation or defects.

26 • CCTV Normalization factor: The number of CCTVs divided by 30. If there are 30 or fewer
27 CCTVs, a normalization factor of 1 should be used.
28
29 • IDS Normalization factor: The number of physical security zones divided by 20. If there are
30 20 or fewer zones, a normalization factor of 1 should be used.

1 **Calculation**
2
3 The performance indicator is calculated using values reported for the previous four quarters. The
4 calculation involves averaging the results of the following two equations.
5

6 $$\text{IDS Unavailability Index} = \frac{\text{IDS Compensatory hours in the previous 4 quarters}}{\text{IDS Normalization Factor x 8760 hrs}}$$

7

8 $$\text{CCTV Unavailability Index} = \frac{\text{CCTV Compensatory hours in the previous 4 quarters}}{\text{CCTV Normalization Factor x 8760 hrs}}$$

9

10 $$\text{Indicator Value} = \frac{\text{IDS Unavilability Index} + \text{CCTV Unavailability Index}}{2}$$

11
12 **Definition of Terms**

13 *Intrusion detection system (IDS)* - E-fields, microwave fields, *etc*.

14 *CCTV* - The closed circuit television cameras that support the IDS.

15 *Normalization factors* - Two factors are used to compensate for larger than nominal size sites.

16 − *IDS Normalization Factor*: Using a nominal number of physical security zones across the
17   industry, the normalization factor for IDS is twenty. If a site has twenty or fewer intrusion
18   detection zones, the normalization factor will be 1. If a site has more zones than 20, the
19   factor is the total number of site zones divided by 20 (*e.g.*, $50 \div 20 = 2.5$).

20 − *CCTV Normalization Factor*: Using a nominal number of perimeter cameras across the
21   industry, the normalization factor for cameras is 30. If a site has thirty or fewer perimeter
22   cameras, the normalization factor is 1. If a site has more than 30 perimeter cameras, the
23   factor is the total number of perimeter cameras divided by 30 (*e.g.*, $50 \div 30 = 1.7$).

24 | Note: The normalization factors are general approximations and may be modified as
25 | experience in the pilot program dictates.

26
27 *Compensatory measures*: Measures used to meet physical security requirements pending the
28 return of equipment to service. Protected Area protection is not diminished by the use of
29 compensatory measures for equipment unavailability.
30
31 *Compensatory man-hours*: The man-hours (expressed to the nearest tenth of an hour) that
32 compensatory measures are in place (posted) to address a degradation in the IDS and CCTV
33 systems. When a portion of the system becomes unavailable—incapable of performing its
34 intended function—and requires posting of compensatory measures, the compensatory man-hour
35 clock is started. The period of time ends when the cause of the degraded state has been repaired,
36 tested, and system declared operable.
37
38 If a zone is posted for a degraded IDS and a CCTV camera goes out in the same posted area , the
39 hours for the posting of the IDS will not be double counted. However, if the IDS problem is
40 corrected and no longer requires compensatory posting but the camera requires posting, the hours
41 will start to count for the CCTV category.

1

2 *Equipment unavailability:* When the system has been posted because of a degraded condition
3 (unavailability), the compensatory hours are counted in the PI calculation. If the degradation is
4 caused by environmental conditions, preventive maintenance or scheduled system upgrade, the
5 compensatory hours are not counted in the PI calculation. However, if the equipment is
6 degraded after preventive maintenance or periodic testing, compensatory posting would be
7 required and the compensatory hours would count. Compensatory hours stop being counted
8 when the equipment deficiency has been corrected, equipment tested and declared back in
9 service.
10

11 **<u>Clarifying Notes</u>**

12 <u>Compensatory posting</u>:

13 •   The posting for this PI is only for the protected area perimeter, not vital area doors or other
14   places such posting may be required.

15 •   Postings for IDS segments for false alarms in excess of security program limits would be
16   counted in the PI. In the absence of a false alarm limit in the security program, qualified
17   individuals can disposition the condition and determine whether compensatory posting is
18   required.

19 •   Some postings are the result of <u>non-equipment failures</u>, which may be the result of
20   test/maintenance conditions. For example, in a situation where a part of the IDS is taken out-
21   of-service to check a condition for false alarms not in excess of security program false alarm
22   limits, no compensatory hours would be counted. If the equipment is determined to have
23   malfunctioned, it is not operable and maintenance/repair is required, the hours would count.
24

25 •   Compensatory hours expended to address simultaneous equipment problems (IDS & CCTV)
26   are counted beginning with the initial piece of equipment that required compensatory hours.
27   When this first piece of equipment is returned to service and no longer requires
28   compensatory measures, the second covered piece of equipment carries the hours. If one IDS
29   zone is required to be covered by more than one compensatory post, the total man-hours of
30   compensatory action are to be counted. If multiple IDS zones are covered by one
31   compensatory post, the man-hours are only counted once.

32 •   IDS equipment issues that do not require compensatory hours would not be counted

33 •   Compensatory man hours for a failed Pan-Tilt-Zoom (PTZ) camera count for the PI only if
34   the PTZ is either being used as a CCTV or is substituting for a failed CCTV.

35 •   The PI metric is based on expended compensatory hours and starts when the IDS or CCTV is
36   actually posted. There are no "fault exposure hours" or other consideration beyond the actual
37   physical compensatory posting. Also, this indicator only uses <u>compensatory man-hours</u> to
38   provide an indication of CCTV or IDS unavailability. If a PTZ camera or other non-
39   personnel (no expended portion of a compensatory man-hour) item is used as the
40   compensatory measure, it is not counted for this PI.

1   • In a situation where security persons are already in place at continuously manned remote
2   location security booths around the perimeter of the site and there is a need to provide
3   compensatory coverage for the loss of IDS equipment, security persons already in these
4   booths can fulfill this function. If they are used to perform the compensatory function, the
5   hours are included in the PI. The man hours for all persons required to provide compensation
6   are counted. If more persons are assigned than required, only the required compensatory man
7   hours would be counted.

8   • Compensatory hours for this PI cover hours expended in posting a security officer as required
9   as compensation for IDS and/or CCTV unavailability because of a degradation or defect. If
10   other problems (e.g., security computer or multiplexer) result in compensatory postings
11   because the IDS/CCTV is no longer capable of performing its intended safeguards function,
12   the hours would count. Equipment malfunctions that do not require compensatory posting
13   are not included in this PI.

14   • If an ancillary system is needed to support proper operability of IDS or CCTV and it fails,
15   and the supported system does not operate as intended, the hours would count. For example,
16   a CCTV camera requires sufficient lighting to perform its function so that such a lighting
17   failure would result in compensatory hours counted for this PI.
18

19 Data reporting: For this performance indicator, rounding may be performed as desired provided
20 it is consistent and the reporting hours are expressed to the nearest tenth of an hour. Information
21 supporting performance indicators is reported on a per unit basis. For performance indicators that
22 reflect site conditions (IDS or CCTV), this requires that the information be repeated for each unit
23 on the site. The criterion for data reporting is from the time the failure or deficiency is identified
24 to the time it is placed back in service.
25

26 Degradation: Required system/equipment/component is no longer available/capable of
27 performing its intended safeguards function—manufacturer's equipment design capability and/or
28 as covered in the PSP.
29

30 Extreme environmental conditions:
31 Compensatory hours do not count for extreme environmental conditions beyond the design
32 specifications of the system, including severe storms, heavy fog, heavy snowfall, and sun glare
33 that renders the IDS or CCTV temporarily inoperable. If after the environmental condition
34 clears, the zone remains unavailable, despite reasonable recovery efforts, the compensatory hours
35 would not begin to be counted until technically feasible corrective action could be completed.
36 For example, a hurricane decimates a portion of the perimeter IDS and certain necessary
37 components have to be obtained from the factory. Any restoration delay would be independent of
38 the licensee's maintenance capability and therefore would not be counted in the indicator.
39

40 Other naturally occurring conditions that are beyond the control of the licensee, such as damage
41 or nuisance alarms from animals are not counted.
42

43 Independent Spent Fuel Storage Installations (ISFSIs): This indicator does not include protective
44 measures associated with such installations.
45

1 Intended function: The ability of a component to detect the presence of an individual or display
2 an image as intended by manufacturer's equipment design capability and/or as covered in the
3 PSP.
4
5 Operational support: E-fields or equivalent that are taken out of service to support plant
6 operations and are not equipment failures but are compensatorily posted do not count for this PI.
7
8 Scheduled equipment upgrade:
9 • In the situation where system degradation results in a condition that cannot be corrected
10   under the normal maintenance program (*e.g.*, engineering evaluation specifies the need for a
11   system/component[10] modification or upgrade), and the system requires compensatory
12   posting, the compensatory hours stop being counted toward the PI for those conditions
13   addressed within the scope of the modification after such an evaluation has been made and
14   the station has formally approved an upgrade with descriptive information about the upgrade
15   plan including scope of the project, anticipated schedule, and expected expenditures. This
16   formally initiated upgrade is the result of established work practices to design, fund, procure,
17   install and test the project. A note should be made in the comment section of the PI submittal
18   that the compensatory hours are being excluded under this provision. Compensatory hour
19   counting resumes when the upgrade is complete and operating as intended as determined by
20   site requirements for sign-off. Reasonableness should be applied with respect to a justifiable
21   length of time the compensatory hours are excluded from the PI.
22
23 • For the case where there are a few particularly troubling zones that result in formal initiation
24   of an entire system upgrade for all zones, counting compensatory hours would stop only for
25   zones out of service for the upgrade. However, if subsequent failures would have been
26   prevented by the planned upgrade those would also be excluded from the count. This
27   exclusion applies regardless of whether the failures are in a zone that precipitated the upgrade
28   action or not, as long as they are in a zone that will be affected by the upgrade, and the
29   upgrade would have prevented the failure.
30
31 Preventive maintenance:
32 • Scheduled preventive maintenance (PM) on system/equipment/component to include
33   probability and/or operability testing. Includes activities necessary to keep the system at the
34   required functional level. Planned plant support activities are considered PM.
35 • If during preventive maintenance or testing, a camera does not function correctly, and can be
36   compensated for by means other than posting an officer, no compensatory man-hours are
37   counted.
38 • Predictive maintenance is treated as preventive maintenance. Since the equipment has not
39   failed and remains capable of performing its intended security function, any maintenance
40   performed in advance of its actual failure is preventive. It is not the intent to create a
41   disincentive to performing maintenance to ensure the security systems perform at their peak
42   reliability and capability.

---

[10] A modification to prevent the circumvention of the IDS (or CCTV) (such as the installation of a razor wire
barrier) would fall under these provisions because the modification would be acting as an ancillary system of the
IDS.

1
2   •   <u>Scheduled system upgrade:</u> Activity to improve, upgrade or enhance system performance, as
3   appropriate, in order to be more effective in its reliability or capability.

1   **Data Example**

Protected Area Security Equipment Performance Indicator

Quarter	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
IDS Compensatory Hours in the qtr	36	48	96	126	65	45	60	55
CCTV Compensatory Hours in the qtr	24	36	100	100	48	56	53	31
IDS Compensatory Hrs in previous 4 qtrs				306	335	332	296	225
CCTV Compensatory Hrs in the previous 4 qtrs				260	284	304	257	188
IDS Normalization Factor	1.05	1.05	1.05	1.05	1.1	1.1	1.1	1.1
CCTV normalization Factor	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3
IDS Unavailability Index				0.033268	0.034765	0.034454	0.030718	0.02335
CCTV Unavailability Index				0.024734	0.024939	0.026695	0.022568	0.016509
					2Q/98	3Q/98	4Q/98	Prev. Q
Indicator Value					0.03	0.03	0.03	0.02

2
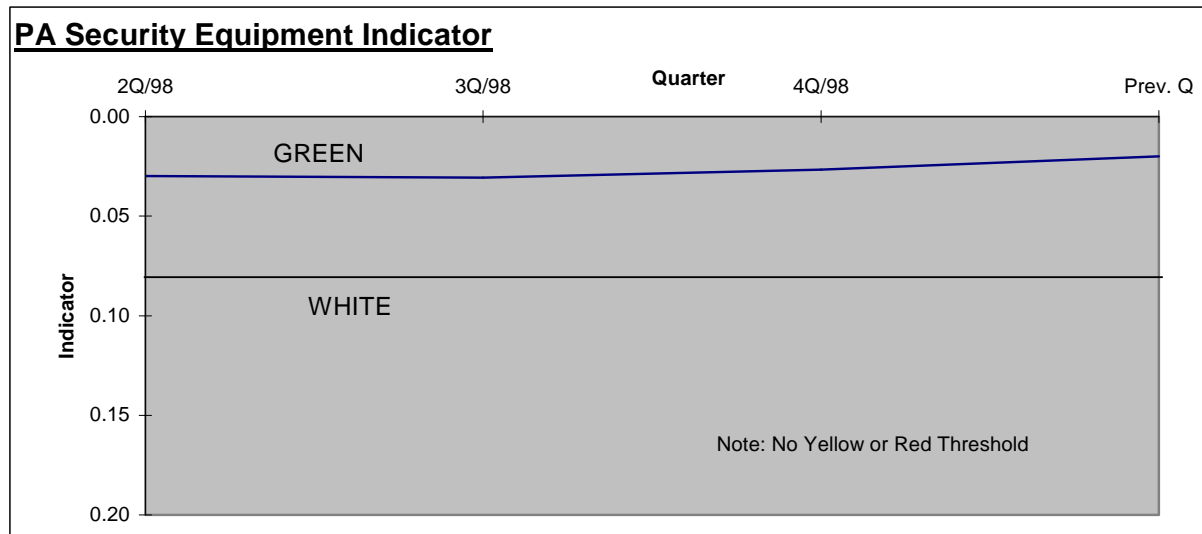
| 1 | **PERSONNEL SCREENING PROGRAM PERFORMANCE** |

Purpose

The screening program performance indicator is used to verify that the unescorted access authorization program has been implemented pursuant to 10 CFR §§ 73.56 & 73.57 to evaluate trustworthiness of personnel prior to granting unescorted access to the protected area. The screening program includes psychological evaluation, an FBI criminal history check, a background check and reference check. The program should be able to verify that persons granted unescorted access to the protected area have satisfactorily completed personal screening and, as a result, are considered to be trustworthy and reliable.

Indicator Definition

The number of reportable failures to properly implement the regulatory requirements.

Data Reporting Elements

The number of failures to implement requirement(s) of 10 CFR Part 73.56 and 73.57 that were reportable during the previous quarter under 10 CFR Part 73 Appendix G.

Calculation

The indicator is a summation of the values reported for the previous four quarters.

Definition of Terms

Reportable event: - a failure in the licensee's program that requires prompt regulatory notification. This is in contrast to a loggable event, which is not considered significant.

Clarifying Notes

The only reportable event is that defined in the PI - "a failure in the licensee's program that requires prompt regulatory notification." If you are not required to make a one-hour report concerning a significant failure to meet regulation it is not included for PI purposes. This indicator provides a measure of the effectiveness of programmatic efforts to implement regulatory requirements outlined in 10 CFR §§ 73.56 and 73.57 only and does not apply to the rest of Part 73. It does not include any reportable events that result from the program operating as intended. For example, if a background investigation reveals a significant event concerning a contract worker but unescorted access had not been granted and proper action was taken, this does not count as a data reporting element. It is not a failure to implement the requirements because the program functioned as implemented in compliance with the requirements.

Where a programmatic failure affected multiple sites, the instance is reported for each affected unit at each affected site.

The criterion for reporting of performance indicators is based on the time the failure or deficiency is identified.

1   <u>**Data Examples**</u>

Personnel Screening Program Indicator								
Quarter	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
10 CFR §73.56 One Hr Reports	0	1	3	0	1	1	0	0
Reportable Events in previous 4 qtrs					2Q/98	3Q/98	4Q/98	Prev. Q
					5	5	2	2

Thresholds	
Green	≤2
White	>2
Yellow	>5

Personnel Screening Program Performance

	2Q/98	3Q/98	**Quarter**	4Q/98	Prev. Q

0	
1	GREEN
2	
3	WHITE
# Reportable Events 4	
5	
6	YELLOW
7	
8	Note: No Red Threshold

2

| 1 | **FITNESS-FOR-DUTY (FFD)/PERSONNEL RELIABILITY PROGRAM PERFORMANCE** |

2 **Purpose**

3 The fitness-for-duty/personnel reliability program performance indicator is used to assess the
4 implemented program for reasonable assurance that personnel are in compliance with associated
5 requirements, 10 CFR Part 26 and § 73.56, to include: suitable inquiry, testing for substance
6 abuse and behavior observation. This trustworthiness and reliability program is designed to
7 minimize the potential for a person's performance or behavior to adversely affect his or her
8 ability to safely and competently perform required duties.
9
10 **Indicator Definition**

11 The number of reportable failures to properly implement the requirements of 10 CFR Part 26 and
12 10 CFR 73.56.
13
14 **Data Reporting Elements**

15 The number of failures to implement fitness-for-duty and behavior observation requirements,
16 reportable during the previous quarter.
17
18 **Calculation**

19 The indicator is a summation of the values reported for the previous four quarters.
20
21 **Definition of Terms**

22 *Reportable event:* a failure in the licensee's program that requires prompt regulatory notification.
23 This is in contrast to a loggable event, which is not considered significant.
24
25 **Clarifying Notes**

26 This indicator provides a measure of the effectiveness of programmatic efforts to implement
27 regulatory requirements outlined in 10 CFR Part 26 and Part 73.56 and does not include any
28 reportable events that result from the program operating as intended. For example, if a contract
29 supervisor is selected for a random drug test, tests positive, and proper action is taken, this does
30 not count as a data reporting element. It is not a failure to implement the requirements because
31 the program functioned as implemented in compliance with the requirements of 10 CFR Part 26.
32
33 Only reports of significant programmatic failures of the implemented regulatory requirements
34 are included in the PIs for access authorization or fitness-for-duty.
35
36 Where a programmatic failure affected multiple sites, the instance is reported for each affected
37 unit at each affected site.
38
39 The criterion for reporting of performance indicators is based on the time the failure or
40 deficiency is identified.
41

1   **Data Example**

FFD/Personnel Reliability								
Quarter	**2Q/97**	**3Q/97**	**4Q/97**	**1Q/98**	**2Q/98**	**3Q/98**	**4Q/98**	**Prev. Q**
10 CFR Part 26 Prompt Reports	0	1	1	0	0	1	0	0
					2Q/98	**3Q/98**	**4Q/98**	**Prev. Q**
Reportable Events in previous 4 qtrs					2	2	1	1
Thresholds								
Green	≤2							
White	>2							
Yellow	>5							
Red	N/A							

FFD/Personnel Reliability Program

2
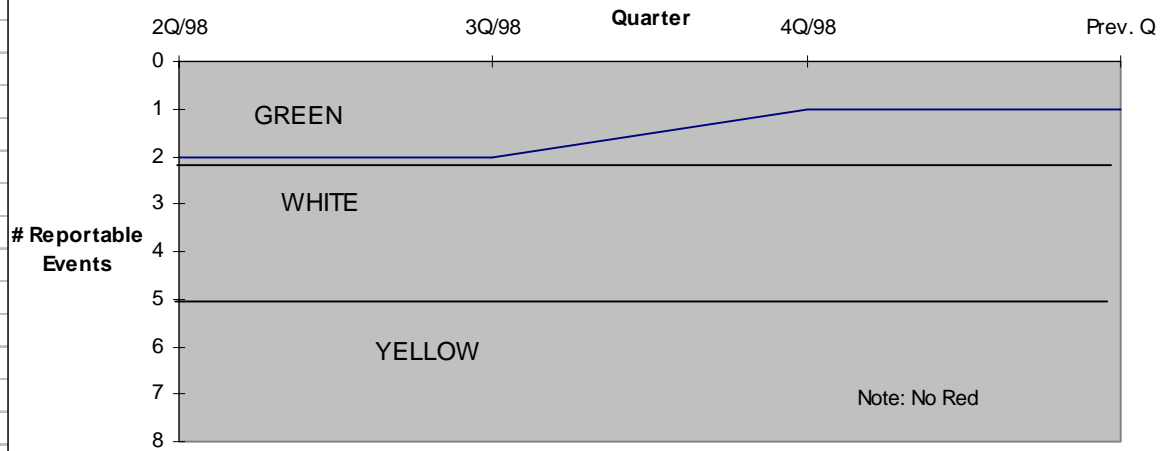
APPENDIX A

Acronyms & Abbreviations

1		
2		
3		
4	AA	Access Authorization
5	AC	Alternating (Electrical) Current
6	AFW	Auxiliary Feedwater System
7	ALARA	As Low As Reasonably Achievable
8	ANS	Alert & Notification System
9	AOT	Allowed Outage Time
10	AOV	Air Operated Valve
11	ATWS	Anticipated Transient Without Scram
12	BWR	Boiling Water Reactor
13	CBOP	Continual Behavior Observation Program
14	CCF	Common Cause Failure
15	CCW	Component Cooling Water
16	CDE	Consolidated Data Entry
17	CDF	Core Damage Frequency
18	CFR	Code of Federal Regulations
19	CCTV	Closed Circuit Television
20	DC	Direct (Electrical) Current
21	DE & AEs	Drills, Exercises and Actual Events
22	EAC	Emergency AC
23	EAL	Emergency Action Levels
24	EDG	Emergency Diesel Generator
25	EOF	Emergency Operations Facility
26	EFW	Emergency Feedwater
27	ERO	Emergency Response Organization
28	ESF	Engineered Safety Features
29	FAQ	Frequently Asked Question
30	FBI	Federal Bureau of Investigations
31	FEMA	Federal Emergency Management Agency
32	FFD	Fitness for Duty
33	FSAR	Final Safety Analysis Report
34	FV	Fussel-Vesely
35	FWCI	Feedwater Coolant Injection
36	IC	Isolation Condenser
37	IDS	Intrusion Detection System
38	ISFSI	Independent Spent Fuel Storage Installation
39	HOV	Hydraulic Operated Valve
40	HPCI	High Pressure Coolant Injection
41	HPCS	High Pressure Core Spray
42	HPSI	High Pressure Safety Injection
43	HVAC	Heating, Ventilation and Air Conditioning
44	INPO	Institute of Nuclear Power Operations
45	LER	Licensee Event Report
46	LPCI	Low Pressure Coolant Injection
47	LPSI	Low Pressure Safety Injection

1	LOCA	Loss of Coolant Accident
2	MD	Motor Driven
3	MOV	Motor Operated Valve
4	MSIV	Main Steam Isolation Valve
5	MSPI	Mitigating Systems Performance Index
6	N/A	Not Applicable
7	NEI	Nuclear Energy Institute
8	NRC	Nuclear Regulatory Commission
9	NSSS	Nuclear Steam Supply System
10	ODCM	Offsite Dose Calculation Manual
11	OSC	Operations Support Center
12	PA	Protected Area
13	PARs	Protective Action Recommendations
14	PI	Performance Indicator
15	PLE	Performance Limit Exceeded
16	PRA	Probabilistic Risk Analysis
17	PSA	Probabilistic Safety Assessment
18	PORV	Power Operated Relief Valve
19	PWR	Pressurized Water Reactor
20	RETS	Radiological Effluent Technical Specifications
21	RCIC	Reactor Core Isolation Cooling
22	RCS	Reactor Coolant System
23	RHR	Residual Heat Removal
24	ROP	Reactor Oversight Process
25	RWST	Refueling Water Storage Tank
26	SOV	Solenoid Operated Valve
27	SPAR	Standardized Plant Analysis Risk
28	SSFF	Safety System Functional Failure
29	SSU	Safety System Unavailability performance indicator
30	SWS	Service Water System
31	TD	Turbine Driven
32	TSC	Technical Support Center
33	UAI	Unavailability Index
34	URI	Unreliability Index

APPENDIX B

STRUCTURE AND FORMAT OF NRC PERFORMANCE INDICATOR DATA FILES

Performance indicator data files submitted to the NRC as part of the Regulatory Oversight Process should conform to structure and format identified below. The INPO CDE software automatically produces files with structure and format outlined below.

File Naming Convention

Each NRC PI data file should be named according to the following convention. The name should contain the unit docket number, underscore, the date and time of creation and (if a change file) a "C" to indicate that the file is a change report. A file extension of .txt is used to indicate a text file.

Example: 05000399_20000103151710.txt

In the above example, the report file is for a plant with a docket number of 05000399 and the file was created on January 3, 2000 at 10 seconds after 3:17 p.m. The absence of a C at the end of the file name indicates that the file is a quarterly data report.

General Structure

Each line of the report begins with a left bracket (e.g., "[") and ends with a right bracket (e.g., "]"). Individual items of information on a line (elements) are separated by a vertical "pipe" (e.g., "|").

Each file begins with [BOF] as the first line and [EOF] as the last line. These indicate the beginning and end of the data file. The file may also contain one or more "buffer" lines at the end of the file to minimize the potential for file corruption. The second line of the file contains the unit docket number and the date and time of file creation (e.g., [05000399|1/2/2000 14:20:32]). Performance indicator information is contained beginning with line 3 through the next to last line (last line is [EOF]). The information contained on each line of performance indicator information consists of the performance indicator ID, applicable quarter/year (month/year for Barrier Integrity indicators), comments, and each performance indicator data element. Table B-1 provides a description of the data elements and order for each line of performance indicator data in a report file.

Example:
[IE01|3Q1998|Comments here|2|2400]

In the above example, the line contains performance indicator data for Unplanned Scrams per 7000 Critical Hours (IE01), during the 3rd quarter of 1998. The applicable comment text is "Comments here". The data elements identify that (see Table B-1) there were 2 unplanned automatic and manual scrams while critical and there were 2400 hours of critical operation during the quarter.

1   **TABLE B-1 – PI DATA ELEMENTS IN NRC DATA REPORT**

2

Performance Indicator	Data Element Number	Description
General Comment	1	Performance Indicator Flag (i.e., GEN)
	2	Report quarter and year (e.g., 1Q2000)
	3	Comment text
Unplanned Scrams per 7,000 Critical Hours	1	Performance Indicator Flag (i.e., IE01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of unplanned automatic and manual scrams while critical in the reporting quarter
	5	Number of hours of critical operation in the reporting quarter
Unplanned Scrams with Loss of Normal Heat Removal	1	Performance Indicator Flag (i.e., IE02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	The number of unplanned automatic and manual scrams while critical in the reporting quarter that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal system
Unplanned Power Changes per 7,000 Critical Hours	1	Performance Indicator Flag (i.e., IE03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of unplanned power changes, excluding scrams, during the reporting quarter
	5	Number of hours of critical operation in the reporting quarter
Safety System Functional Failures	1	Performance Indicator Flag (i.e., MS05)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of safety system functional failures during the reporting quarter
Mitigating Systems Performance Index (MSPI)– Emergency AC Power Systems	1	Performance Indicator Flag (i.e., MS06)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Unavailability Index
	5	Unreliability Index
	6	Performance Limit Exceeded
Mitigating Systems Performance Index (MSPI)- High Pressure Injection Systems	1	Performance Indicator Flag (i.e., MS07)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Unavailability Index
	5	Unreliability Index
	6	Performance Limit Exceeded

Performance Indicator	Data Element Number	Description
Mitigating Systems Performance Index (MSPI)– Heat Removal Systems	1	Performance Indicator Flag (i.e., MS08)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Unavailability Index
	5	Unreliability Index
	6	Performance Limit Exceeded
Mitigating Systems Performance Index (MSPI)– Residual Heat Removal Systems	1	Performance Indicator Flag (i.e., MS09)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Unavailability Index
	5	Unreliability Index
	6	Performance Limit Exceeded
Mitigating Systems Performance Index (MSPI)– Cooling Water Systems	1	Performance Indicator Flag (i.e., MS10)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Unavailability Index
	5	Unreliability Index
	6	Performance Limit Exceeded
Reactor Coolant System Activity (RCSA)	1	Performance Indicator Flag (i.e., BI01)
	2	Month and year (e.g., 3/2000)
	3	Comment text
	4	Maximum calculated RCS activity, in micro curies per gram dose equivalent Iodine 131, as required by technical specifications, for reporting month
	5	Technical Specification limit for RCS activity in micro curies per gram does equivalent Iodine 131
Reactor Coolant System Identified Leakage (RCSL)	1	Performance Indicator Flag (i.e., BI02)
	2	Month and year (e.g., 3/2000)
	3	Comment text
	4	Maximum RCS Identified Leakage calculation for reporting month in gpm
	5	Technical Specification limit for RCS Identified Leakage in gpm
Emergency Response Organization Drill/Exercise Performance	1	Performance Indicator Flag (i.e., EP01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of drill, exercise and actual event opportunities performed timely and accurately during the reporting quarter
	5	Number of drill, exercise and actual event opportunities during the reporting quarter
Emergency Response Organization (ERO) Participation	1	Performance Indicator Flag (i.e.,EP02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Total Key ERO members that have participated in a drill, exercise, or actual event in the previous 8 qrtrs
	5	Total number of Key ERO personnel at end of reporting quarter

Performance Indicator	Data Element Number	Description
Alert & Notification System Reliability	1	Performance Indicator Flag (i.e., EP03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Total number of successful ANS siren-tests during the reporting quarter
	5	Total number of ANS sirens tested during the reporting quarter
Occupational Exposure Control Effectiveness	1	Performance Indicator Flag (i.e., OR01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of technical specification high radiation area occurrences during the reporting quarter
	5	Number of very high radiation area occurrences during the reporting quarter
	6	The number of unintended exposure occurrences during the reporting quarter
RETS/ODCM Radiological Effluent Indicator	1	Performance Indicator Flag (i.e., PR01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of RETS/ODCM occurrences in the quarter
Protected Area Security Equipment Performance Indicator	1	Performance Indicator Flag (i.e., PP01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	IDS Compensatory Hours in the quarter
	5	CCTV Compensatory Hours in the quarter
	6	IDS Normalization Factor
	7	CCTV Normalization Factor
Personnel Screening Program Indicator	1	Performance Indicator Flag (i.e., PP02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	10 CFR §73.56 One Hr Reports
FFD/Personnel Reliability	1	Performance Indicator Flag (i.e., PP03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of failures to implement fitness-for-duty and behavior observation requirements, reportable during the reporting quarter.

1

1
APPENDIX C

3
Background Information and Cornerstone Development
5

INTRODUCTION

This section discusses the overall objectives and basis for the performance indicators used for each of the seven cornerstone areas. A more in-depth discussion of the background behind each of the performance indicators identified in the main report may be found in SECY 99-07.

INITIATING EVENTS CORNERSTONE

GENERAL DESCRIPTION

The objective of this cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions, during shutdown as well as power operations. When such an event occurs in conjunction with equipment and human failures, a reactor accident may occur. Licensees can therefore reduce the likelihood of a reactor accident by maintaining a low frequency of these initiating events. Such events include reactor trips due to turbine trip, loss of feedwater, loss of offsite power, and other reactor transients. There are a few key attributes of licensee performance that determine the frequency of initiating events at a plant.

PERFORMANCE INDICATORS

PRAs have shown that risk is often determined by initiating events of low frequency, rather than those that occur with a relatively higher frequency. Such low-frequency, high-risk events have been considered in selecting the PIs for this cornerstone. All of the PIs used in this cornerstone are counts of either initiating events, or transients that could lead to initiating events (see Table 1). They have face validity for their intended use because they are quantifiable, have a logical relationship to safety performance expectations, are meaningful, and the data are readily available. The PIs by themselves are not necessarily related to risk. They are however, the first step in a sequence which could, in conjunction with equipment failures, human errors, and off-normal plant configurations, result in a nuclear reactor accident. They also provide indication of problems that, if uncorrected, increase the risk of an accident. In most cases, where PIs are suitable for identifying problems, they are sufficient as well, since problems that are not severe enough to cause an initiating event (and therefore result in a PI count) are of low risk significance. In those cases, no baseline inspection is required (the exception is shutdown configuration control, for which supplemental baseline inspections is necessary).

1   # MITIGATING SYSTEMS CORNERSTONE

2   ## GENERAL DESCRIPTION

3   The objective of this cornerstone is to ensure the availability, reliability, and capability of systems
4   that respond to initiating events to prevent undesirable consequences (i.e., core damage). When
5   such an event occurs in conjunction with equipment and human failures, a reactor accident may
6   result. Licensees therefore reduce the likelihood of reactor accidents by enhancing the availability
7   and reliability of mitigating systems. Mitigating systems include those systems associated with
8   safety injection, residual heat removal, and emergency AC power. This cornerstone includes
9   mitigating systems that respond to both operating and shutdown events.

10   ## PERFORMANCE INDICATORS

11   While safety systems and components are generally thought of as those that are designed for
12   design-basis accidents, not all mitigating systems have the same risk importance. PRAs have
13   shown that risk is often influenced not only by front-line mitigating systems, but also by support
14   systems and equipment. Such systems and equipment, both safety- and nonsafety-related, have
15   been considered in selecting the PIs for this cornerstone. The PIs are all direct counts of either
16   mitigating system availability or reliability or surrogates of mitigating system performance. They
17   have face validity for their intended use because they are quantifiable, have a logical relationship
18   to safety performance expectations, are meaningful, and the data are readily available. Not all
19   aspects of licensee performance can be monitored by PIs. Risk-significant areas not covered by
20   PIs will be assessed through inspection.

21   # BARRIER INTEGRITY CORNERSTONE

22   ## GENERAL DESCRIPTION

23   The purpose of this cornerstone is to provide reasonable assurance that the physical design
24   barriers (fuel cladding, reactor coolant system, and containment) protect the public from
25   radionuclide releases caused by accidents or events. These barriers play an important role in
26   supporting the NRC Strategic Plan goal for nuclear reactor safety, "Prevent radiation-related
27   deaths or illnesses due to civilian nuclear reactors." The defense in depth provided by the
28   physical design barriers which comprise this cornerstone allow achievement of the reactor safety
29   goal.

30   ## PERFORMANCE INDICATORS

31   The performance indicators for this cornerstone cover two of the three physical design barriers.
32   The first barrier is the fuel cladding. Maintaining the integrity of this barrier prevents the release
33   of radioactive fission products to the reactor coolant system, the second barrier. Maintaining the
34   integrity of the reactor coolant system reduces the likelihood of loss of coolant accident initiating
35   events and prevents the release of radioactive fission products to the containment atmosphere in
36   transients and other events. Performance indicators for reactor coolant system activity and reactor
37   coolant system leakage monitor the integrity of the first two physical design barriers. Even if
38   significant quantities of radionuclides are released into the containment atmosphere, maintaining
39   the integrity of the third barrier, the containment, will limit radioactive releases to the

1   environment and limit the threat to the public health and safety. The integrity of the containment
2   barrier is ensured through the inspection process.
3
4   Therefore, there are three desired results associated with the barrier integrity cornerstone. These
5   are to maintain the functionality of the fuel cladding, the reactor coolant system, and the
6   containment.

7   **EMERGENCY PREPAREDNESS CORNERSTONE**

8   **GENERAL DESCRIPTION**

9   Emergency Preparedness (EP) is the final barrier in the *defense in depth* approach to safety that
10   NRC regulations provide for ensuring the adequate protection of the public health and safety.
11   Emergency Preparedness is a fundamental cornerstone of the Reactor Safety Strategic
12   Performance Area. 10 CFR Part 50.47 and Appendix E to Part 50, define the requirements of an
13   EP program and a licensee commits to implementation of these requirements through an
14   Emergency Plan (the Plan). The performance indicators for this cornerstone are designed to
15   ensure that the licensee is capable of implementing adequate measures to protect the public health
16   and safety in the event of a radiological emergency.

17   **PERFORMANCE INDICATORS**

18   Compliance of EP programs with regulation is assessed through observation of response to
19   simulated emergencies and through routine inspection of onsite programs. Demonstration
20   exercises involving onsite and offsite programs, form the key observational tool used to support,
21   on a continuing basis, the reasonable assurance finding that *adequate protective measures can
22   and will be taken in the event of a radiological emergency.* This is especially true for the most
23   risk significant facets of the EP program. This being the case, the PIs for onsite EP draw
24   significantly from performance during simulated emergencies and actual declared emergencies,
25   but are supplemented by direct NRC inspection and inspection of licensee self assessment. NRC
26   assessment of the adequacy of offsite EP will rely (as it does currently) on regular FEMA
27   evaluations.

28   **OCCUPATIONAL EXPOSURE CORNERSTONE**

29   **GENERAL DESCRIPTION**

30   This cornerstone includes the attributes and the bases for adequately protecting the health and
31   safety of workers involved with exposure to radiation from licensed and unlicensed radioactive
32   material during routine operations at civilian nuclear reactors. The desired result is the adequate
33   protection of worker health and safety from this exposure. The cornerstone uses as its bases the
34   occupational dose limits specified in 10 CFR 20 Subpart C and the operating principle of
35   maintaining worker exposure "as low as reasonably achievable (ALARA)" in accordance with
36   10 CFR 20.1101. These radiation protection criteria are based upon the assumptions that a linear
37   relationship, without threshold, exists between dose and the probability of stochastic health
38   effects (radiological risk); the severity of each type of stochastic health effect is independent of
39   dose; and nonstochastic radiation-induced health effects can be prevented by limiting exposures

1　below thresholds for their induction.　Thus, 10 CFR Part 20 requires occupational doses to be
2　maintained ALARA with the exposure limits defined in 10 CFR 20 Subpart C constituting the
3　maximum allowable radiological risk.　Industry experience has shown that the occurrences of
4　uncontrolled occupational exposure that potentially could result in an individual exceeding a dose
5　limit have been low frequency events.　These potential overexposure incidents are associated with
6　radiation fields exceeding 1000 millirem per hour (mrem/hr) and have involved the loss of one or
7　more radiation protection controls (barriers) established to manage and control worker exposure.
8　The probability of undesirable health effects to workers can be maintained within acceptable
9　levels by controlling occupational exposures to radiation and radioactive materials to prevent
10　regulatory overexposures and by implementing an aggressive and effective ALARA program to
11　monitor, control and minimize worker dose.

12　**PERFORMANCE INDICATORS**

13　A combined performance indicator is used to assess licensee performance in controlling worker
14　doses during work activities associated with high radiation fields or elevated airborne
15　radioactivity areas.　The PI was selected based upon its ability to provide an objective measure of
16　an uncontrolled measurable worker exposure or a loss of access controls for areas having
17　radiation fields exceeding 1000 millirem per hour (mrem/hr).　The data for the PI are currently
18　being collected by most licensees in their corrective action programs.　The PI either directly
19　measures the occurrence of unanticipated and uncontrolled dose exceeding a percentage of the
20　regulatory limits or identifies the failure of barriers established to prevent unauthorized entry into
21　those areas having dose rates exceeding 1000 mrem/hr.　The indicator may identify declining
22　performance in procedural guidance, training, radiological monitoring, and in exposure and
23　contamination control prior to exceeding a regulatory dose limit.　The effectiveness of the
24　licensee's assessment and corrective action program is considered a cross-cutting issue and is
25　addressed elsewhere.

26　# PUBLIC EXPOSURE CORNERSTONE

27　**GENERAL DESCRIPTION**

28　This cornerstone includes the attributes and the bases for adequately protecting public health and
29　safety from exposure to radioactive material released into the public domain as a result of routine
30　civilian nuclear reactor operations.　The desired result is the adequate protection of public health
31　and safety from this exposure.　These releases include routine gaseous and liquid radioactive
32　effluent discharges, the inadvertent release of solid contaminated materials, and the offsite
33　transport of radioactive materials and wastes.　The cornerstone uses as its bases, the dose limits
34　for individual members of the public specified in 10 CFR 20, Subpart D; design objectives
35　detailed in Appendix I to 10 CFR Part 50 which defines what doses to members of the public
36　from effluent releases are "as low as reasonably achievable" (ALARA); and the exposure and
37　contamination limits for transportation activities detailed in 10 CFR Part 71 and associated
38　Department of Transportation (DOT) regulations.　These radiation protection standards require
39　doses to the public be maintained ALARA with the regulatory limits constituting the maximum
40　allowable radiological risk based on the linear relationship between dose received and the
41　probability of adverse health effects.

1   **PERFORMANCE INDICATORS**

2   One PI for the radioactive effluent release program has been initially developed to monitor for
3   inaccurate or increasing projected offsite doses. The effluent radiological occurrence (ERO) PI
4   does not evaluate performance of the radiological environmental monitoring program (REMP)
5   which will be assessed through the routine baseline inspection. For transportation activities, the
6   infrequent occurrences of elevated radiation or contamination limits in the public domain from
7   this measurement area precluded identification of a corresponding indicator. A second PI has been
8   proposed for future use to monitor the inadvertent release of potentially contaminated materials
9   which could result in a measurable dose to a member of the public. These indicators will provide
10   partial assessments of licensee radioactive effluent monitoring and offsite material release
11   activities and were selected to identify decreasing performance prior to exceeding public
12   regulatory dose limits.

13   # PHYSICAL SECURITY CORNERSTONE

14   **GENERAL DESCRIPTION**

15   This cornerstone addresses the attributes and establishes the basis to provide assurance that the
16   physical protection system can protect against the design basis threat of radiological sabotage as
17   defined in 10 CFR 73.1(a). The key attributes in this cornerstone are based on the defense in
18   depth concept and are intended to provide protection against both external and internal threats.
19   To date, there have been no attempted assaults with the intent to commit radiological sabotage
20   and, although there has been no PRA work done in the area of safeguards, it is assumed that there
21   exists a small probability of an attempt to commit radiological sabotage. Although radiological
22   sabotage is assumed to be a small probability, it is also assumed to be risk significant since a
23   successful sabotage attempt could result in initiating an event with the potential for disabling of
24   the safety systems necessary to mitigate the consequences of the event with substantial
25   consequence to public health and safety. An effective security program decreases the risk to
26   public health and safety associated with an attempt to commit radiological sabotage.

27   **PERFORMANCE INDICATORS**

28   Three performance indicators are used to assess licensee performance in the Physical Protection
29   and Access Authorization Systems. The PIs were selected based on their ability to provide
30   objective measures of performance.
31
32   The performance of the physical protection system will be measured by the percent of the time all
33   components (barriers, alarms and assessment aids) in the systems are available and capable of
34   performing their intended function. When systems are not available and capable of performing
35   their intended function, compensatory measures must be implemented. Compensatory measures
36   are considered acceptable pending equipment being returned to service, but historically have
37   been found to degrade over time. The degradation of compensatory measures over time, along
38   with the additional costs associated with implementation of compensatory measures provides the
39   incentive for timely maintenance/I&C support to return equipment to service. The percent of time
40   equipment is available and capable of performing its intended function will provide data on the
41   effectiveness of the maintenance process and also provide a method of monitoring equipment
42   degradation as a result of aging that could adversely impact on reliability.

1
2   Two performance indicators are used to measure the Access Authorization System. The
3   performance indicators for this system will count the number of reportable events that reflect
4   program degradations.   This data is currently available and there are regulatory requirements to
5   report significant events in the areas of Personnel Screening and FFD. The Behavior Observation
6   significant events are captured in the FFD reporting requirements.
7
8
9

1 <u>**APPENDIX D**</u>

2
3 **Plant Specific Design Issues**
4
5 This appendix provides additional guidance on plant specific Frequently Asked Questions and
6 identifies resolutions to performance indicator reporting issues that are specific to individual plant
7 designs. FAQs should be submitted as soon as possible once the Licensee and resident inspector or
8 region have identified an issue on which there is not agreement. If the Licensee is not sure how to
9 interpret a situation and the quarterly report is due, an FAQ should be submitted and a comment in
10 the PI comment field would be appropriate. It is incumbent on NRC and the Licensee to work
11 expeditiously and cooperatively, sharing concerns, questions and data in order that the issue can be
12 resolved quickly.
13
14 **Plant-specific Issues**
15
16 The NEI 99-02 guidance was written to accommodate situations anticipated to arise at a typical
17 nuclear power plant. However, uncommon plant designs or unique conditions may exist that have
18 not been anticipated. In these cases, licensees should first apply the guidance as written to
19 determine the impact on the indicators. Then, if the licensee believes that there are unique
20 circumstances sufficient to warrant an exception to the guidance as written, the licensee should
21 submit a Frequently Asked Question to NEI for consideration at a public meeting with the NRC.
22 If the FAQ is approved, the issue will be included in Appendix D of this document as a plant-
23 specific issue.
24
25 Some provisions in NEI 99-02 may differ from the design, programs, or procedures of a particular
26 plant. Examples include (1) the overlapping Emergency Planning Zones at Kewaunee and Point
27 Beach and (2) actions to address storm-driven debris on intake structures.
28
29 In evaluating each request for a plant-specific exception, this forum will take into consideration
30 factors related to the particular issue.
31
32 **Kewaunee and Point Beach**
33
34 <u>Issue:</u> The Kewaunee and Point Beach sites have overlapping Emergency Planning Zones (EPZ).
35 We report siren data to the Federal Emergency Management Agency (FEMA) grouped by criterion
36 other than entire EPZs (such as along county lines). May we report siren data for the PIs in the
37 same fashion to eliminate confusion and prevent 'double reporting' of sirens that exist in both
38 EPZs? Kewaunee and Point Beach share a portion of EPZs and responsibility for the sirens has
39 been divided along the county line that runs between the two sites. FEMA has accepted this, and
40 so far the NRC has accepted this informally.
41
42 <u>Resolution:</u> The purpose of the Alert and Notification System Reliability PI is to indicate the
43 licensee's ability to maintain risk-significant EP equipment. In this unique case, each neighboring
44 plant maintains sirens in a different county. Although the EPZ is shared, the plants do not share
45 the same site. In this case, it is appropriate for the licensees to report the sirens they are

1   responsible for. The NRC Web site display of information for each site will contain a footnote
2   recognizing this shared EPZ responsibility.
3
4   **North Anna and Surry**
5   Continue to report PP01 in accordance with the current guidance in NEI 99-02.
6
7   **Grand Gulf**
8
9   Issue: Of the 43 sirens associated with our Alert Notification System, two of the sirens are located
10 in flood plain areas. During periods of high river water, the areas associated with these sirens are
11 inaccessible to personnel and are uninhabitable. During periods of high water, the electrical power
12 to the entire area and the sirens is turned off. The frequency and duration of this occurrence varies
13 based upon river conditions but has occurred every year for the past five years and lasts an average
14 of two months on each occasion.
15
16 Assuming the sirens located in the flood plain areas are operable prior to the flooded and
17 uninhabitable conditions, would these sirens be required to be included in the performance
18 indicator during flooded conditions?
19
20 Resolution: If sirens are not available for operation due to high flood water conditions and the area
21 is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question
22 will not be counted in the numerator or denominator of the Performance Indicator for that testing
23 period.
24
25 **Diablo Canyon Units 1 and 2**
26
27 Issue: At Diablo Canyon (DC), intrusion of marine debris (kelp and other marine vegetation) at the
28 circulating water intake structures can occur and, under extreme storm conditions result in high
29 differential pressure across the circulating water traveling screens, loss of circulating water pumps
30 and loss of condenser. Over the past several years, DC has taken significant steps, including
31 changes in operating strategy as well as equipment enhancements, to reduce the vulnerability of
32 the plant to this phenomenon. DC has also taken efforts to minimize kelp, however environmental
33 restrictions on kelp removal and the infeasibility of removing (and maintaining removal of)
34 extensive marine growth for several miles around the plant prevent them from eliminating the
35 source if the storm-driven debris. To minimize the challenge to the plant under storm conditions
36 which could likely result in loss of both circulating water pumps, DC procedurally reduces power
37 to 25% power or less. From this power level, the plant can be safely shut down by control rod
38 motion and use of atmospheric dump valves without the need for a reactor trip.
39
40 Is this anticipatory plant shutdown in response to an external event, where DC has taken all
41 reasonable actions within environmental constraints to minimize debris quantity and impact, able
42 to be excluded from being counted under IE01 and IE02?
43
44 Resolution: In consideration of the intent of the performance indicators and the extensive actions
45 taken by PG&E to reduce the plant challenge associated with shutdowns in response to severe
46 storm-initiated debris loading, the following interpretation will be applied to Diablo Canyon. A
47 controlled shutdown from reduced power (less than 25%), which is performed in conjunction with
48 securing of the circulating water pumps to protect the associated traveling screens from damage

due to excessive debris loading under severe storm conditions, will not be considered a "scram." If, however, the actions taken in response to excessive debris loading result in the initiation of a reactor trip (manual or automatic), the event would require counting under both the Unplanned Scrams (IE01) and Scrams with a Loss of Normal Heat Removal (IE02) indicators.

Diablo Canyon

Issue: The response to PI FAQ #158 states "Anticipatory power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions."

Due to its location on the Pacific coast, Diablo Canyon is subject to kelp/debris intrusion at the circulating water intake structure under extreme storm conditions. If the rate of debris intrusion is sufficiently high, the traveling screens at the intake of the main condenser circulating water pumps (CWPs) become overwhelmed. This results in high differential pressure across the screens and necessitates a shutdown of the affected CWP(s) to prevent damage to the screens.

To minimize the challenge to the plant should a shutdown of the CWP(s) be necessary in order to protect the circulating water screens, the following operating strategy has been adopted:

- If a storm of sufficient intensity is predicted, reactor power is procedurally curtailed to 50% in anticipation of the potential need to shut down one of the two operating CWPs. Although the plant could remain at 100% power, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing a CWP. One CWP is fully capable of supporting plant operation at 50% power.

- If one CWP must be secured based on adverse traveling screen/condenser differential pressure, the procedure directs operators to immediately reduce power to less than 25% in anticipation of the potential need to secure the remaining CWP. Although plant operation at 50% power could continue indefinitely with one CWP, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing the remaining CWP. Reactor shutdown below 25% power is within the capability of the control rods, being driven in at the maximum rate, in conjunction with operation of the atmospheric dump valves.

- Should traveling screen differential pressure remain high and cavitation of the remaining CWP is imminent/occurring, the CWP is shutdown and a controlled reactor shutdown is initiated. Based on anticipatory actions taken as described above, it is expected that a reactor trip would be avoided under these circumstances.

How should each of the above power reductions (i.e., 100% to 50%, 50% to 25%, and 25% to reactor shutdown) count under the Unplanned Power Changes PI?

Resolution: Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%, that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours in advance. Neither of these anticipatory power reductions would count under the Unplanned Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power change since such a reduction is forced and can therefore not be considered anticipatory.

1

D.C. Cook

3

4 Issue: The definition for the Reactor Coolant System (RCS) Leakage performance indicator is
5 "The maximum RCS Identified Leakage in gallons per minute each month per the technical
6 specification limit and expressed as a percentage of the technical specification limit."

7

8 Cook Nuclear Plant Unit 1 and 2 report Identified Leakage since the Technical Specifications have
9 a limit for Identified Leakage with no limit for Total Leakage. Plant procedures for RCS leakage
10 calculation requires RCS leakage into collection tanks to be counted as Unidentified Leakage due
11 to non-RCS sources directed to the collection tanks. All calculated

12 leakage is considered Unidentified until the leakage reaches an administrative limit at which point
13 an evaluation is performed to identify the leakage and calculate the leak rate. Consequently,
14 Identified Leakage is unchanged until the administrative limit is reached. This does not allow for
15 trending allowed RCS Leakage. The procedural requirements will remain in place until plant
16 modifications can be made to remove the non-RCS sources from the drain collection tanks. What
17 alternative method should be used to trend allowed RCS leakage for the Barrier Integrity
18 Cornerstone?

19

20 Resolution: Report the maximum RCS Total Leakage calculated in gallons per minute each month
21 per the plant procedures instead of the calculated Identified Leakage. This value will be compared
22 to and expressed as a percentage of the combined Technical Specification Limits for Identified and
23 Unidentified Leakage. This reporting is considered acceptable to provide consistency in reporting
24 for plants with the described plant configuration.

25

Nine Mile Point

27

28 Issue: Some plants are designed to have a residual transfer of the non-safety electrical buses from
29 the generator to an off-site power source when the turbine trip is caused by a generator protective
30 feature. The residual transfer automatically trips large electrical loads to prevent damaging plant
31 equipment during reenergization of the switchgear. These large loads include the reactor
32 feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual
33 transfer is completed the operators can manually restart the pumps from the control room. The
34 turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be
35 counted as a scram with a loss of normal heat removal?

36

37 Resolution: No. In this instance, the electrical transfer scheme performed as designed following a
38 scram and the residual transfer. In addition the pumps can be started from the control room.
39 Therefore, this would not count as a scram with a loss of normal heat removal.

40

Point Beach

42

43 Issue: On June 27th, Point Beach Unit 2 was manually scrammed, in accordance with Abnormal
44 Operating Procedure AOP 13A, "Circulating Water System Malfunction," and power was reduced
45 on Point Beach Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the

1   pump bay attributable to an influx of small forage fish (alewives). The large influx of fish created a
2   high differential water level across the traveling screens and ultimately failure of shear pins for the
3   screen drive system, leading to a rapid drop in bay level. The plant knows when the alewife
4   spawning and hatching seasons occur and the effects of Lake Michigan temperature fluctuations on
5   the route of alewife schools. It was aware of the presence of large schools at other Lake Michigan
6   plants this spring and discussed those events and the potential of them occurring at Point Beach at
7   the morning staff meetings. During the thirty years of plant operation, there have been a few
8   instances where a large number of fish entered the plant circ water system.
9
10   High alewife populations coupled with seasonal variations, lake conditions and wind conditions
11   created the situation that resulted in the down power on June 27th. Point Beach staff believe that
12   these are uncontrollable environmental conditions. Plant procedures are in place which direct
13   actions when the water level in the pump bay decreases. However, it is not possible to predict the
14   exact time of an influx of schooling fish nor the massive population of fish that arrived in the
15   pump bay. Page 17 of NEI 99-02 Revision 1 states, "Anticipated power changes greater than 20%
16   in response to expected problems (such as accumulation of marine debris and biological
17   contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72
18   hours in advance may not need to be counted if they are not reactive to the sudden discovery of
19   off-normal conditions." Would this situation count as an unplanned power change?
20
21   Resolution: No. The influx of alewives was expected as evidenced by the discussion of events at
22   other plants on Lake Michigan but was not predictable greater than 72 hours in advance due to the
23   variables involved. Large schools of alewives are a result of environmental and aquatic conditions
24   that occur in certain seasons. The response to the drop in bay level is proceduralized.
25

26   Quad Cities

27
28   Issue:1) At Quad Cities, load reductions in excess of 20% during hot weather are sometimes
29   necessary if the limits of the NPDES Permit limit would be exceeded. Actual initiation of a power
30   change is not predictable 72 hrs in advance, as actions are not taken until temperatures actually
31   reach predefined levels. Would these power changes be counted?
32   2) Power reductions are sometimes necessary during summer hot weather and/or lowered river
33   level conditions when conducting standard condenser flow reversal evolutions. The load reduction
34   timing is not predictable 72 hrs in advance as the accumulation of Mississippi River debris/silt
35   drives the actual initiation of each evolution. The main condenser system design allows for
36   cleaning by flow reversal, which is procedurally controlled to assure sufficient vacuum is
37   maintained. It is sometimes necessary, due to high inlet temperatures, to reduce power more than
38   20% to meet procedural requirements during the flow reversal evolution. These conditions are
39   similar to those previously described in FAQ 158. Would these power changes be counted for this
40   indicator?
41
42   Resolution:
43   1) No.
44   2) No. Power changes in excess of 20% for the purposes of condenser flow reversal are not
45   counted as an unplanned power change.
46

1 **River Bend Station**

2

3 Issue: River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02
4 guidance, specifically page 80, lines 36 and 37 "Only calculations of RCS leakage that are
5 computed in accordance with the calculational methodology requirements of the Technical
6 Specifications are counted in this indicator."
7 NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage
8 Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this,
9 the indicator uses the identified leakage as a percentage of the technical specification allowable
10 identified leakage. Moreover, the definition provided is "the maximum RCS identified leakage in
11 gallons per minute each month per technical specifications and expressed as a percentage of the
12 technical specification limit."
13 The RBS Technical Specification (TS) states "Verify RCS unidentified LEAKAGE, total
14 LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency)." RBS
15 accomplishes this surveillance requirement using an approved station procedure that requires the
16 leakage values from the 0100 and 1300 calculation be used as the leakage "of record" for the
17 purpose of satisfying the TS surveillance requirement. These two data points are then used in the
18 population of data subject to selection for performance indicator calculation each quarter (highest
19 monthly value is used).
20 The RBS approved TS method for determining RCS leakage uses programmable controller
21 generated points for total RCS leakage. The RBS' programmable controller calculates the average
22 total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it
23 monitors, showing the last four calculations to indicate a trend and printing the total unidentified
24 LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable
25 controller will print this report any time an alarm value is exceeded. The printout can be ordered
26 manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating
27 leakage values at any frequency, the equipment generates hourly values that are summarized in a
28 daily report.
29 The RBS' TS Bases states "In conjunction with alarms and other administrative controls, a 12 hour
30 Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for
31 tracking required trends."
32 The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the
33 approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In
34 this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values
35 to satisfy the TS surveillance requirements. The NRC Resident has taken the position that all
36 hourly values from the daily report should be used for the RCS leakage performance indicator
37 determination, even though they are not required by the station surveillance procedure. The
38 Resident maintains that all hourly values use the same method as the 0100 and 1300 values and
39 should be included in the leakage determination.
40 Is the Licensee interpretation of NEI 99-02 correct?
41 Resolution:
42 All calculations of RCS leakage that are computed in accordance with the calculational
43 methodology requirements of the Technical Specifications are counted in this indicator. Since the
44 River Bend Station leakage calculation is an average of the previous 24 hourly leakage rates which
45 are calculated in accordance with the technical specification methodology, it is acceptable for
46 River Bend Station to include only those calculations that are performed to meet the technical
47 specifications surveillance requirement when determining the highest monthly values for reporting.
48 The ROP Working Group is forming a task force to review this performance indicator based on
49 industry practices.

1
Ginna
3
4 Issue: NEI 99-02 Rev 1, states in part on page 14, lines 11 - 14: "Intentional operator actions to
5 control the reactor water level or cool down rate, such as securing main feedwater or closing the
6 MSIVs, are not counted in this indicator, as long as the normal heat removal path can be easily
7 recovered from the control room without the need for diagnosis or repair to restore the normal heat
8 removal path."
9 Revision 1 added the wording "…as long as the normal heat removal path can be easily recovered
10 from the control room without the need for diagnosis or repair to restore the normal hear removal
11 path." to this statement.
12 If the MSIVs are closed to control cooldown rate following a scram or normal shutdown at our
13 station, the MSIVs are not reopened. In Mode 3, Operators typically close the MSIVs as part of
14 procedurally directed shutdown activities to assist in controlling the cooldown rate and pressurizer
15 level, and to perform IST and Technical Specification required testing. Once the Operators
16 intentionally close the MSIVs, they, by procedure, do not reopen them. In fact, for normal plant
17 shutdowns on 3/1/99 and 9/18/00, operators closed the MSIVs as early as 2 hours upon entering
18 Mode 3. For two reactor trips, one on 4/23/99 from intermediate range issues and one on 4/27/99
19 from an OTDT issue, the MSIVs were closed for control purposes within ~10 minutes of the
20 reactor trip as allowed by plant procedures. The secondary system was available in both of these
21 instances.
22 The MSIV bypass valves at our station cannot be operated from the Main Control Board or
23 anywhere else in the Control Room. Original design of our station's MSIVs requires an Aux
24 Operator to open a bypass valve located at the MSIVs prior to reopening the MSIVs, thus requiring
25 operator action outside the control room. This action is an operational task that is considered to be
26 uncomplicated and is virtually certain to be successful during the conditions in which it is
27 performed. However, it would require diagnosis, as it is not the normal procedural method for the
28 Operators to control cooldown rate once the MSIVs are closed. Does the closure of the MSIVs,
29 while in Mode 3 or lower, to control cooldown rate, pressurizer level, or to perform testing
30 following a scram constitute a scram with loss of normal heat removal?
31
32 Resolution: No. Because the normal plant response to a scram without complications requires the
33 MSIVs to be closed to control the cooldown rate, and the operators are instructed and trained to do
34 this after every scram, such a scram would not count as a scram with loss of normal heat removal
35
Catawba
37 Issue: Catawba Nuclear Station has 89 sirens in their 10-mile EPZ; 68 of these are located in York
38 County. Duke Power's siren testing program includes a full cycle test for performance indicator
39 purposes once each calendar quarter. On Tuesday, September 7, 2004, York County sounded the
40 sirens in their county's portion of the EPZ to alert the public of the need to take protective actions
41 for a Tornado Warning. Catawba is uncertain whether to include the results of the actual activation
42 in their ANS PI statistics. The definition in NEI 99-02 does not address actual siren activations. In
43 contrast, the Drill/Exercise Performance (DEP) Indicator requires that actual events be included in
44 the PI. Should the performance during the actual siren activation be included in the Alert and
45 Notification System (ANS) Performance Indicator Data?
46

1   <u>Resolution:</u> For this instance, Catawba may include the results of the September 7, 2004 actual
2   siren activations in their ANS PI data. However, for all future instances, no actual siren activation
3   data results shall be included in licensees' ANS PI data.

APPENDIX E

FREQUENTLY ASKED QUESTIONS

Purpose

The Frequently Asked Question (FAQ) process is the mechanism for resolving interpretation issues with NEI 99-02. FAQs and responses are posted on the NRC Website (www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html) and INPO's Consolidated Data Entry webpage. They represent NRC approved interpretations of performance indicator guidance and should be treated as an extension of NEI 99-02.

There are several reasons for submitting an FAQ:

1. *To clarify the guidance when the licensee and NRC regional staff do not agree on the meaning or how to apply the guidance to a particular situation.*
2. *To provide guidance for a class of plants whose design or system functions differ from that described in the guidance.*
3. *To request an exemption from the guidance for plant-specific circumstances, such as design features, procedures, or unique conditions.*

Proposed changes to the guidance are not a reason to submit an FAQ. A formal process exists for changing the guidance, which usually includes analysis and piloting before being implemented.   In very rare circumstances, while reviewing an FAQ, the Industry/NRC working group may determine that a change in the guidance is necessary.

The FAQ process is not the arena in which to resolve interpretation issues with any other NRC regulatory documents. In addition, the FAQ process is not used to make licensing or engineering decisions.

Process

1. Issue identification

Either the licensee or the NRC may identify the need for an interpretation of the guidance. FAQs should be submitted as soon as possible once the licensee and resident inspector or region have identified an issue on which there is not agreement.

The licensee submits the FAQ by email to pihelp@nei.org. The email should include "FAQ" as part of the subject line and should provide the name and phone number of a contact person. If the licensee is not sure how to interpret a situation and the quarterly report is due, an FAQ should be submitted and a comment in the PI comment field would be appropriate. If the licensee has reasonable confidence that its position will be accepted, it is under no obligation to report the information (e.g., unavailability). Conversely, if the licensee is not confident that it will succeed in its FAQ, the information should be included in the submitted data. In either case, the report can be amended, if required, at a later date.

1   2. Expeditiousness, Completeness and Factual Agreement
2
3   In order for the performance indicators to be a timely element of the ROP, it is incumbent on
4   NRC and the licensee to work expeditiously and cooperatively, sharing concerns, questions and
5   data in order that the issue can be resolved quickly. Where possible, agreement should be
6   achieved prior to submittal of the FAQ on the factual elements of the FAQ, e.g., the engineering,
7   maintenance, or operational situation. The FAQ must describe the situation clearly and
8   concisely and must be complete and accurate in all respects. If agreement cannot be reached on
9   the wording of the FAQ, NRC will provide its alternate view to the licensee for inclusion in the
10   FAQ.
11
12   3. FAQ Format
13
14   See figure E-1 for the format for submitting an FAQ. It is important to provide contact
15   information and whether the FAQ should be considered generic to all plants, or only specific to
16   the licensee submitting the FAQ. In most cases the FAQ will become effective as soon as
17   possible; however, the licensee can recommend an effective date. The question section of the
18   FAQ includes the specific wording of the guidance which needs to be interpreted, the
19   circumstances involved, and the specific question. All relevant information should be included
20   and should be as complete as possible. Incomplete or omitted information will delay the
21   resolution of the FAQ. The licensee also provides a proposed response to the FAQ.   The
22   response should answer the question and provide the reasoning for the answer. (There must not
23   be any new information presented in the response that was not already discussed in the question.)
24   The NRC may or may not opt to request that the FAQ include an alternative response. Finally,
25   the FAQ may include proposed wording to revise the guidance in the next revision.
26
27   4. Screening of licensee FAQs
28
29   FAQs are reviewed by NEI and revision may be requested. After acceptance by NEI, the FAQ is
30   reviewed by the industry's Safety Performance Assessment Task Force. Additional wording
31   may be suggested to the licensee. In some cases, the task force may believe the FAQ is without
32   merit and may recommend that the FAQ be withdrawn. An accepted FAQ is entered in the FAQ
33   log which includes all unresolved FAQs. The log is forwarded to NRC and the task force
34   members approximately one week prior to the (approximately) monthly ROP meeting between
35   the task force and NRC.
36
37   5. Public Meeting Discussions of FAQs
38
39   The FAQ log is reviewed at each monthly ROP meeting, and the Industry/NRC working group is
40   responsible for achieving a consensus response, if possible. In most cases, the licensee is
41   expected to present and explain the details of its FAQ. Licensee and resident/regional NRC staff
42   are usually available (at the meeting or by teleconferencing) to respond to questions posed by the
43   Industry/NRC) working group. The new FAQ is introduced by the licensee to ensure the
44   working group understands the issues, but discussion of the FAQ is usually referred to the next
45   meeting, when participants will have had an opportunity to research the issues involved. At
46   subsequent meetings, the FAQ will be discussed in detail, until all of the facts have been
47   resolved and consensus has been reached on the response. The FAQ will then be considered
48   "Tentatively Approved," and one additional month will be allowed for reconsideration. At the
49   following meeting the FAQ becomes "Final." Typically, an FAQ is introduced one month; the

1   facts are discussed for two or three months and a tentative decision reached; and it goes final the
2   following month.
3
4   In some limited cases (involving an issue with no contention and where exigent resolution is
5   needed), it is possible for the ROP working group to reach immediate consensus and take the
6   FAQ to Final; however, this will generally be an exception.
7
8   6.   Appeal Process
9
10 Once the facts and circumstances are agreed upon, if consensus cannot be reached after two
11 consecutive working group meetings, the FAQ will be referred to the NRC Director of the
12 Division of Inspection Program Management (DIPM). The director will conduct a public
13 meeting at which both the licensee and NRC will present their positions as well as respond to
14 any questions from the director. The director then will make the determination. Any additional
15 appeal to higher management is outside of this process and is solely at the licensee's discretion
16 and initiative.
17
18 7.   Promulgation and Effective Date of FAQs
19
20 Once approved by NRC, the accepted response will be posted on the NRC Website and is treated
21 as an extension of this guideline.
22
23 The NRC Website will identify the date of original posting for FAQs and responses. Unless
24 otherwise directed in an FAQ response, FAQs are to be applied to the data submittal for the
25 quarter in which the FAQ was posted and beyond. For example, an FAQ with a posting date of
26 3/31/2000 would apply to 1st quarter 2000 PI data, submitted in April 2000 and subsequent data
27 submittals. However, an FAQ with a posting date of 4/1/2000 would apply on a forward fit basis
28 to 2nd quarter 2000 PI data submitted in July 2000. Licensees are encouraged to check the NRC
29 Web site frequently, particularly at the end of the reporting period, for FAQs that may have
30 applicability for their sites.
31
32 At the time of a revision of NEI 99-02, active FAQs will be reviewed for inclusion in the text.
33 These FAQs will then be placed in an "archived" file. Archived FAQs are for historical
34 purposes and are not considered to be part of NEI 99-02.

1 **FAQ TEMPLATE**
2
3
4 Plant: _____
5 Date of Event: _____
6 Submittal Date: _____
7 Licensee Contact: _____ Tel/email: _____
8 NRC Contact: _____ Tel/email: _____
9
10 Performance Indicator:
11
12 Site-Specific FAQ (Appendix D)? Yes or No
13
14 FAQ requested to become effective when approved or _____
15
16 Question Section
17
18 NEI 99-02 Guidance needing interpretation (include page and line citation):
19
20
21 Event or circumstances requiring guidance interpretation:
22
23
24 If licensee and NRC resident/region do not agree on the facts and circumstances explain
25
26
27 Potentially relevant existing FAQ numbers
28
29
30 Response Section
31
32 Proposed Resolution of FAQ
33
34
35 If appropriate, provide proposed rewording of guidance for inclusion in next revision.
36
37
38
39
40
41
42
43
44
45
46
47
48 Figure E-1

APPENDIX F

METHODOLOGIES FOR COMPUTING THE UNAVAILABILITY INDEX, THE UNRELIABILITY INDEX AND COMPONENT PERFORMANCE LIMITS

This appendix provides the details of three calculations: the System Unavailability Index, the System Unreliability Index, and component performance limits.

F 1. SYSTEM UNAVAILABILITY INDEX (UAI) DUE TO TRAIN UNAVAILABILITY

Unavailability is monitored at the train level for the purpose of calculating UAI. The process for calculation of the System Unavailability Index has three major steps:

- Identification of system trains

- Collection of plant data

- Calculation of UAI

The first of these steps is performed for the initial setup of the index calculation (and if there are significant changes to plant configuration). The second step has some parts that are performed initially and then only performed again when a revision to the plant specific PRA is made or changes are made to the normal preventive maintenance practices. Other parts of the calculation are performed periodically to obtain the data elements reported to the NRC. This section provides the detailed guidance for the calculation of UAI.

F 1.1. IDENTIFICATION OF SYSTEM TRAINS

The identification of system trains is accomplished in two steps:

- Determine the system boundaries

- Identify the trains within the system

The use of simplified P&IDs can be used to document the results of this step and will also facilitate the completion of the directions in section 2.1.1 later in this document.

F 1.1.1. MONITORED FUNCTIONS AND SYSTEM BOUNDARIES

The first step in the identification of system trains is to define the monitored functions and system boundaries. Include all components within the system boundary that are required to satisfy the monitored functions of the system.

The monitored functions of the system are those functions in section 5 of this appendix that have been determined to be risk-significant functions per NUMARC 93-01 and are reflected in the PRA. If none of the functions listed in section five for a system are determined to be risk significant, then:

- If only one function is listed for a system, then this function is the monitored function (for example, CE NSSS designs use the Containment Spray system for RHR but this system is redundant to the containment coolers and may not be risk significant. The Containment Spray system would be monitored.)

- If multiple functions are listed for a system, the most risk significant function is the monitored function for the system. Use the Birnbaum Importance values to determine which function is most risk significant.

For fluid systems the boundary should extend from the water source (e.g., tanks, sumps, etc.) to the injection point (e.g., RCS, Steam Generators). For example, high-pressure injection may have both an injection mode with suction from the refueling water storage tank and a recirculation mode with suction from the containment sump. For Emergency AC systems, the system consists of all class 1E generators at the station.

Additional system specific guidance on system boundaries can be found in section 5 titled "Additional Guidance for Specific Systems" at the end of this appendix.

Some common conditions that may occur are discussed below.

System Interface Boundaries
For water connections from systems that provide cooling water to a <u>single</u> component in a monitored system, the final connecting valve is included in the boundary of the frontline system rather than the cooling water system. For example, for service water that provides cooling to support an AFW pump, only the final valve in the service water system that supplies the cooling water to the AFW system is included in the AFW system scope. This same valve is not included in the cooling water support system scope. The equivalent valve in the return path, if present, will also be included in the frontline system boundary.

Water Sources and Inventory
Water tanks are not considered to be monitored components. As such, they do not contribute to URI. However, periods of insufficient water inventory contribute to UAI if they result in loss of the monitored train function for the required mission time. If additional water sources are required to satisfy train mission times, only the connecting active valve from the additional water source is considered as a monitored component for calculating UAI. If there are valves in the primary water source that must change state to permit use of the additional water source, these valves are considered monitored and should be included in UAI for the system.

Unit Cross-Tie Capability
At multiple unit sites cross ties between systems frequently exist between units. For example at a two unit site, the Unit 1 Emergency Diesel Generators may be able to be connected to the Unit 2 electrical bus through cross tie breakers. In this case the Unit 1 EAC system boundary would end at the cross tie breaker in Unit 1 that is closed to establish the cross-tie. The similar breaker in Unit 2 would be the system boundary for the Unit 2 EAC system. Similarly, for fluid systems the fluid system boundary would end at the valve that is opened to establish the cross-tie.

Common Components
Some components in a system may be common to more than one system, in which case the unavailability of a common component is included in all affected systems.

1   **F 1.1.2.   Identification of Trains within the System**

2   Each monitored system shall then be divided into trains to facilitate the monitoring of
3   unavailability.
4

5   *A train* consists of a group of components that together provide the monitored functions of the
6   system described in the "additional guidance for specific mitigating systems". The number of
7   trains in a system is generally determined as follows:
8

9   •   For systems that provide cooling of fluids, the number of trains is determined by the number
10   of parallel heat exchangers, or the number of parallel pumps, or the minimum number of
11   parallel flow paths, whichever is fewer.

12   •   For emergency AC power systems the number of trains is the number of class 1E emergency
13   (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power
14   shutdown loads in the event of a loss of off-site power. (For example, this does not include the
15   diesel generator dedicated to the BWR HPCS system, which is included in the scope of the
16   HPCS system.)

17   Some components or flow paths may be included in the scope of more than one train. For
18   example, one set of flow regulating valves and isolation valves in a three-pump, two-steam
19   generator system are included in the motor-driven pump train with which they are electrically
20   associated, but they are also included (along with the redundant set of valves) in the turbine-
21   driven pump train. In these instances, the effects of unavailability of the valves should be reported
22   in all affected trains. Similarly, when two trains provide flow to a common header, the effect of
23   isolation or flow regulating valve failures in paths connected to the header should be considered
24   in both trains.
25

26   Additional system specific guidance on train definition can be found in section 5 titled
27   "Additional Guidance for Specific Systems" at the end of this appendix.

28   Additional guidance is provided below for the following specific circumstances that are
29   commonly encountered:

30   •   Cooling Water Support System Trains

31   •   Swing Trains and Components Shared Between Units

32   •   Maintenance Trains and Installed Spares

33   •   Trains or Segments that Cannot Be Removed from Service.
34

35   Cooling Water Support Systems and Trains
36   The cooling water function is typically accomplished by multiple systems, such as service water
37   and component cooling water. A separate value for UAI will be calculated for each of the systems
38   in this indicator and then they will be added together to calculate an overall UAI value.
39

40   In addition, cooling water systems are frequently not configured in discrete trains. In this case, the
41   system should be divided into logical segments and each segment treated as a train. This approach

is also valid for other fluid systems that are not configured in obvious trains. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments (such as suction and discharge headers), then the number of pumps and line segments would be the number of trains.

Unit Swing trains and components shared between units
Swing trains/components are trains/components that can be aligned to any unit. To be credited as such, their swing capability must be modeled in the PRA to provide an appropriate Fussell-Vesely value.

Maintenance Trains and Installed Spares
Some power plants have systems with extra trains to allow preventive maintenance to be carried out with the unit at power without impacting the monitored function of the system. That is, one of the remaining trains may fail, but the system can still perform its monitored function. To be a maintenance train, a train must not be needed to perform the system's monitored function.

An "installed spare" is a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without impacting the number of trains available to achieve the monitored function of the system. To be an "installed spare," a component must not be needed for any train of the system to perform the monitored function. A typical installed spare configuration is a two train system with a third pump that can be aligned to either train (both from a power and flow perspective), but is normally not aligned and when it is not aligned receives no auto start signal. In a two train system where each train has two 100% capacity pumps that are both normally aligned, the pumps are not considered installed spares, but are redundant components within that train.

Unavailability of an installed spare is not monitored. Trains in a system with an installed spare are not considered to be unavailable when the installed spare is aligned to that train. In the example above, a train would be considered to be unavailable if neither the normal component nor the spare component is aligned to the train.

Trains or Segments that Cannot Be Removed from Service
In some normally operating systems (e.g. Cooling Water Systems), there may exist trains or segments of the system that cannot physically be removed from service while the plant is operating at power for the following reasons:
- Directly causes a plant trip
- Procedures direct a plant trip
- Technical Specifications requires immediate shutdown (LCO 3.0.3)

These should be documented in the Basis Document and not included in unavailability monitoring.

F 1.2. Collection of Plant Data

Plant data for the UAI portion of the index includes:

- Actual train total unavailability (planned and unplanned) data for the most recent 12 quarter period collected on a quarterly basis,
- Plant specific baseline planned unavailability, and
- Generic baseline unplanned unavailability.

Each of these data inputs to UAI will be discussed in the following sections.

F 1.2.1.   ACTUAL TRAIN UNAVAILABILITY

The Consolidated Data Entry (CDE) inputs for this parameter are Train Planned Unavailable Hours and Train Unplanned Unavailable Hours. Critical hours are derived from reactor startup and shutdown occurrences. The actual calculation of Train Unavailability is performed by CDE.

Train Unavailability: Train unavailability is the ratio of the hours the train was unavailable to perform its monitored functions due to planned or unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters.

Train unavailable hours: The hours the train was not able to perform its monitored function while critical. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's monitored functions. In all cases, a train that is considered to be OPERABLE is also considered to be available. Unavailability must be by train; do not use average unavailability for each train because trains may have unequal risk weights.

Planned unavailable hours: These hours include time a train or segment is removed from service for a reason other than equipment failure or human error. Examples of activities included in planned unavailable hours are preventive maintenance, testing, equipment modification, or any other time equipment is electively removed from service to correct a degraded condition that had not resulted in loss of function. Based on the plant history of previous three years, planned baseline hours for functional equipment that is electively removed from service but could not be planned in advance can be estimated and the basis documented. When used in the calculation of UAI, if the planned unavailable hours are less than the baseline planned unavailable hours, the planned unavailable hours will be set equal to the baseline value.

Unplanned unavailable hours: These hours include elapsed time between the discovery and the restoration to service of an equipment failure or human error (such as a misalignment) that makes the train unavailable. Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that resulted in the equipment being non-functional even though no demand or failure actually occurred. Unavailability due to mis-positioning of components that renders a train incapable of performing its monitored functions is included in unplanned unavailability for the time required to recover the monitored function.

Additional guidance on the following topics for counting train unavailable hours is provided below.

- Short Duration Unavailability

- Credit for Operator Recovery Actions to Restore the Monitored Function

Short Duration Unavailability
Trains are generally considered to be available during periodic system or equipment realignments to swap components or flow paths as part of normal operations. Evolutions or surveillance tests that result in less than 15 minutes of unavailable hours per train at a time need not be counted as unavailable hours. Licensees should compile a list of surveillances or evolutions that meet this criterion and have it available for inspector review. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact.

Credit for Operator Recovery Actions to Restore the Monitored Functions

1. *During testing or operational alignment*:

   Unavailability of a monitored function during testing or operational alignment need not be included if the test or operational alignment configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a designated operator[11] stationed locally for that purpose. Restoration actions must be contained in a written procedure[12], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test or operational alignment for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions.

   The individual performing the restoration function can be the person conducting the test or operational alignment and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the test or operational alignment may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

   Under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires; or clearing tags). In addition, some manual operations of systems designed to operate automatically, such as manually controlling HPCI turbine to establish and control

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[11] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[12] Including restoration steps in an approved test procedure.

injection flow, are not virtually certain to be successful. These situations should be resolved on a case-by-case basis through the FAQ process.

2. *During Maintenance*

Unavailability of a monitored function during maintenance need not be included if the monitored function can be promptly restored either by an operator in the control room or by a designated operator[13] stationed locally for that purpose. Restoration actions must be contained in an approved procedure, must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at a proper location throughout the duration of the maintenance activity for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration of monitored functions that are virtually certain to be successful (i.e., probability nearly equal to 1).

The individual performing the restoration function can be the person performing the maintenance and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the maintenance activity may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful chaotic conditions otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires, or clearing tags). These situations should be resolved on a case-by-case basis through the FAQ process.

3. *During degraded conditions*

In accordance with current regulatory guidance, licensees may credit limited operator actions to determine that degraded equipment remains operable in accordance with Technical Specifications. If a train is determined to be operable, then it is also available. Beyond this, no credit is allowed for operator actions during degraded conditions that render the train unavailable to perform its monitored functions.

F 1.2.2.   PLANT SPECIFIC BASELINE PLANNED UNAVAILABILITY

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value

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[13] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions. A review of any changes made in 2005 should be performed prior to initial implementation.

Some significant maintenance evolutions, such as EDG overhauls, are performed at an interval greater than the three year monitoring period (5 or 10 year intervals). The baseline planned unavailability should be revised as necessary during the quarter prior to the planned maintenance evolution and then removed after twelve quarters. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability is changed at the discretion of the licensee. Revised values will be used in the calculation the quarter following their update.

To determine the initial value of planned unavailability:

1) Record the total train unavailable hours reported under the Reactor Oversight Process for 2002-2004.

2) Subtract any fault exposure hours still included in the 2002-2004 period.

3) Subtract unplanned unavailable hours.

4) Add any on-line overhaul hours[14] and any other planned unavailability previously excluded under SSU in accordance with NEI 99-02, but not excluded under the MSPI. Short duration unavailability, for example, would not be added back in because it is excluded under both SSU and MSPI.

5) Add any planned unavailable hours for functions monitored under MSPI which were not monitored under SSU in NEI 99-02.

6) Subtract any unavailable hours reported when the reactor was not critical.

7) Subtract hours cascaded onto monitored systems by support systems. (However, do not subtract any hours already subtracted in the above steps.)

8) Divide the hours derived from steps 1-7 above by the total critical hours during 2002-2004. This is the baseline planned unavailability.

Support cooling planned unavailability baseline data is based on plant specific maintenance rule unavailability for years 2002-2004. Maintenance Rule practices do not typically differentiate planned from unplanned unavailability. However, best efforts will be made to differentiate planned and unplanned unavailability during this time period.

If maintenance practices at a plant have changed since the baseline years (e.g. increased planned online maintenance due to extended AOTs), then the baseline values should be adjusted to reflect the current maintenance practices and the basis for the adjustment documented in the plant's MSPI Basis Document.

F 1.2.3. GENERIC BASELINE UNPLANNED UNAVAILABILITY

The unplanned unavailability values are contained in Table 1 and remain fixed. They are based on ROP PI industry data from 1999 through 2001. (Most baseline data used in PIs come from the

---

[14] Note: The plant-specific PRA should model significant on-line overhaul hours.

1   1995-1997 time period. However, in this case, the 1999-2001 ROP data are preferable, because
2   the ROP data breaks out systems separately. Some of the industry 1995-1997 INPO data combine
3   systems, such as HPCI and RCIC, and do not include PWR RHR. It is important to note that the
4   data for the two periods is very similar.)
5

6   **Table 1. Historical Unplanned Unavailability Train Values**
7   **(Based on ROP Industry wide Data for 1999 through 2001)**

SYSTEM	UNPLANNED UNAVAILABILITY/TRAIN
EAC	1.7 E-03
PWR HPSI	6.1 E-04
PWR AFW (TD)	9.1 E-04
PWR AFW (MD)	6.9 E-04
PWR AFW (DieselD)	7.6 E-04
PWR (except CE) RHR	4.2 E-04
CE RHR	1.1 E-03
BWR HPCI*	3.3 E-03
BWR HPCS	5.4 E-04
BWR FWCI	Use plant specific Maintenance Rule data for 2002-2004
BWR RCIC	2.9 E-03
BWR IC	1.4E-03
BWR RHR	1.2 E-03
Support Cooling	Use plant specific Maintenance Rule data for 2002-2004

8   * Oyster Creek to use Core Spray plant specific Maintenance Rule data for 2002-2004

9

10 <u>Generic Baseline Unplanned Unavailability for Front Line systems divided into segments for</u>
11 <u>unavailability monitoring</u>

12 If a front line system is divided into segments rather than trains, the following approach is
13 followed for determining the generic unplanned unavailability:

14   1.   Determine the number of trains used for SSU unavailability reporting that was in use prior
15   to MSPI.

16   2.   Multiply the appropriate value from Table 1 by the number of trains determined in (1).

17   3.   Take the result and distribute it among the MSPI segments, such that the sum is equal to
18   (2) for the whole MSPI system.

19

20 Unplanned unavailability baseline data for the support cooling systems should be developed from
21 plant specific Maintenance Rule data from the period 2002-2004. Maintenance Rule practices do
22 not typically differentiate planned from unplanned unavailability. However, best efforts will be

1 made to differentiate planned and unplanned unavailability during this time period. NOTE: The
2 sum of planned and unplanned unavailability cannot exceed the total unavailability.
3
4 ## F 1.3. CALCULATION OF UAI

5 The specific formula for the calculation of UAI is provided in this section. Each term in the
6 formula will be defined individually and specific guidance provided for the calculation of each
7 term in the equation. Required inputs to the INPO Consolidated Data Entry (CDE) System will be
8 identified.
9
10 Calculation of System UAI due to train unavailability is as follows:

11 $$UAI = \sum_{j=1}^{n} UAI_{tj} \qquad \text{Eq. 1}$$

12 where the summation is over the number of trains (n) and UAI_t is the unavailability index for a
13 train.
14 Calculation of UAI_t for each train due to actual train unavailability is as follows:

15 $$UAI_t = CDF_p \left[\frac{FV_{UAp}}{UA_p} \right]_{max} (UA_t - UA_{BLt}) \qquad , \qquad \text{Eq. 2}$$

16 where:
17   CDF_p is the plant-specific Core Damage Frequency,
18   FV_{UAp} is the train-specific Fussell-Vesely value for unavailability,
19   UA_P is the plant-specific PRA value of unavailability for the train,
20   UA_t is the actual unavailability of train t, defined as:

21 $$UA_t = \frac{\text{Unavailable hours (planned and unplanned) during the previous 12 quarters while critical}}{\text{Critical hours during the previous 12 quarters}}$$

22
23   and, determined in section 1.2.1
24   UA_{BLt} is the historical baseline unavailability value for the train (sum of planned
25   unavailability determined in section 1.2.2 and unplanned unavailability in section
26   1.2.3)
27 A method for calculation of the quantities in equation 2 from importance measures calculated
28 using cutsets from an existing PRA solution is discussed in sections F 1.3.1 through F 1.3.3.
29
30 An alternate approach, based on re-quantification of the PRA model, and calculation of the
31 importance measures from first principles is also an acceptable method. Guidance on this alternate
32 method is contained in section 6 of this appendix. A plant using this alternate approach should use
33 the guidance in section 6 and skip sections F 1.3.1 through F 1.3.3.
34
35 ### F 1.3.1. TRUNCATION LEVELS

36 The values of importance measures calculated using an existing cutset solution are influenced by
37 the truncation level of the solution. The truncation level chosen for the solution should be 7 orders
38 of magnitude less than the baseline CDF for the alternative defined in sections F 1.3.2 and F
39 1.3.3.
40

1 As an alternative to using this truncation level, the following sensitivity study may be performed
2 to establish the acceptability of a higher (e.g. 6 orders of magnitude) truncation level.
3
4   1. Solve the model at the truncation level you intend to use. (e.g. 6 orders of magnitude
5   below the baseline CDF)
6   2. Identify the limiting Birnbaum value for each component. (this is the case 1 value)
7   3. Solve the model again with a truncation 10 times larger (e.g. 5 orders of magnitude below
8   the baseline CDF)
9   4. Identify the limiting Birnbaum value for each component. (this is the case 2 value)
10   5. For each component with Birnbaum-case 1 greater than 1.0E-06 calculate the ratio
11   [(Birnbaum-case 2)/(Birnbaum-case 1)]
12   6. If the value for the calculated ratio is greater than 0.8 for all components with Birnbaum-
13   case 1 value greater than 1.0E-06, then the case 1 truncation level may be used for this
14   analysis.
15
16 This process may need to be repeated several times with successively lower truncation levels to
17 achieve acceptable results.
18
19 **F 1.3.2.   CALCULATION OF CORE DAMAGE FREQUENCY (CDFP)**

20 The Core Damage Frequency is a CDE input value. The required value is the internal events,
21 average maintenance, at power value. Internal flooding and fire are not included in this calculated
22 value. In general, all inputs to this indicator from the PRA are calculated from the internal events
23 model only.
24
25 **F 1.3.3.   CALCULATION OF [FV/UA]MAX FOR EACH TRAIN**

26 FV and UA are separate CDE input values. Equation 2 includes a term that is the ratio of a
27 Fussell-Vesely importance value divided by the related unavailability or probability. This ratio is
28 calculated for each train in the system and both the FV and UA are CDE inputs. (It may be
29 recognized that the quantity [FV/UA] multiplied by the CDF is the Birnbaum importance
30 measure, which is used in section 2.3.3.)
31
32 Calculation of these quantities is generally complex, but in the specific application used here, can
33 be greatly simplified.
34
35 The simplifying feature of this application is that only those components (or the associated basic
36 events) that can make a train unavailable are considered in the performance index. Components
37 within a train that can each make the train unavailable are logically equivalent and the ratio
38 FV/UA is a constant value for any basic event in that train. It can also be shown that for a given
39 component or train represented by multiple basic events, the ratio of the two values for the
40 component or train is equal to the ratio of values for any basic event within the train. Or:

41
$$\frac{FV_{be}}{UA_{be}} = \frac{FVUA_p}{UA_p} = \text{Constant}$$

42 Thus, the process for determining the value of this ratio for any train is to identify a basic event
43 that fails the train, determine the probability for the event, determine the associated FV value for
44 the event and then calculate the ratio.

The set of basic events to be considered for use in this section will obviously include any test and maintenance (T&M) events applicable to the train under consideration. Basic events that represent failure on demand that are logically equivalent to the test and maintenance events should also be considered. (Note that many PRAs use logic that does not allow T&M events for multiple trains to appear in the same cutset because this condition is prohibited by Technical specifications. For PRAs that use this approach, failure on demand events will not be logically equivalent to the T&M events, and only the T&M events should be considered.) Failure to run events should **not** be considered as they are often not logically equivalent to test and maintenance events. Use the basic event from this set that results in the largest ratio (hence the maximum notation on the bracket) to minimize the effects of truncation on the calculation.

Some systems have multiple modes of operation, such as PWR HPSI systems that operate in injection as well as recirculation modes. In these systems all monitored components are not logically equivalent; unavailability of the pump fails all operating modes while unavailability of the sump suction valves only fails the recirculation mode. In cases such as these, if unavailability events exist separately for the components within a train, the appropriate ratio to use is the maximum.

F 1.3.4.   CORRECTIONS TO FV/UA RATIO

Treatment of PRA Modeling Asymmetries
In systems with rotated normally running pumps (e. g. cooling water systems), the PRA models may assume one pump is always the running and another is in standby. For example, a service water system may have two 100% capacity pumps in one train, an A and B pump. In practice the A and B pumps are rotated and each one is the running pump 50% of the time. In the PRA model however, the A pump is assumed to be always running and the B pump is always in assumed to be in standby. This will result in one pump appearing to be more important than the other when they are, in fact, of equal importance. This asymmetry in importance is driven by the assumption in the PRA, not the design of the plant.

In the case where the system is known to be symmetric in importance, for calculation of UAI, the importance measures for each train, or segment, should be averaged and the average applied to each train or segment. Care should be taken when applying this method to be sure the system is actually symmetric.

If the system is not symmetric and the capability exists to specify a specific alignment in the PRA model, the model should be solved in each specific alignment and the importance measures for the different alignments combined by a weighted average based on the estimated time each specific alignment is used in the plant.

Cooling Water and Service Water System [FV/UA]max Values
Component Cooling Water Systems (CCW) and Service Water Systems (SWS) at some nuclear stations contribute to risk in two ways. First, the systems provide cooling to equipment used for the mitigation of events and second, the failures (and unavailability) in the systems may also

1 result in the initiation of an event. The contribution to risk from failures to provide cooling to
2 other plant equipment is modeled directly through dependencies in the PRA model.
3 The contribution to risk from failures to provide cooling to other plant equipment is modeled
4 directly through dependencies in the PRA model. However, the contribution due to event
5 initiation is treated in four general ways in current PRAs:
6
7 1) The use of linked initiating event fault trees for these systems with the same basic event
8   names used in the initiator and mitigation trees.

9 2) The use of linked initiating event fault trees for these systems with different basic event names
10   used in the initiator and mitigation trees.

11 3) Fault tree solutions are generated for these systems external to the PRA and the calculated
12   value is used in the PRA as a point estimate

13 4) A point estimate value is generated for the initiator using industry and plant specific event
14   data and used in the PRA.

15 Each of these methods is discussed below.
16
17 *Modeling Method 1*
18 If a PRA uses the first modeling option, then the FV values calculated will reflect the total
19 contribution to risk for a component in the system. No additional correction to the FV values is
20 required.
21
22 *Modeling Methods 2 and 3*
23 The corrected ratio may be calculated as described for modeling method 4 or by the method
24 described below.
25
26 If a linked initiating event fault tree with different basic events used in the initiator and mitigation
27 trees is the modeling approach taken, or fault tree solutions are generated for these systems
28 external to the PRA and the calculated value is used in the PRA as a point estimate, then the
29 corrected ratio is given by:

30
$$[FV/UA]_{corr} = \left[\frac{FVc}{UAc} + \sum_{m=1}^{i} \left\{ \frac{IE_{m,n}(1) - IE_{m,n}(0)}{IE_{m,n}(q_n)} * FVie_m \right\} \right].$$

31
32 In this expression the summation is taken over all system initiators i that involve component n,
33 where
34   *FVc* is the Fussell-Vesely for component *C* as calculated from the PRA Model. This does
35   not include any contribution from initiating events,
36   *UAc* is the basic event probability used in computing *FVc*; i.e. in the system response
37   models,
38      $IE_{m,n}(q_n)$ is the system initiator frequency of initiating event m when the component n
39   unreliability basic event is q_n. The event chosen in the initiator tree should represent the
40   same failure mode for the component as the event chosen for UAc,
41      $IE_{m,n}(1)$ is as above but $q_n=1$,
42      $IE_{m,n}(0)$ is as above but $q_n=0$
43   and

FVie$_m$ is the Fussell-Vesely importance contribution for the initiating event m to the CDF. Since *FV* and *UA* are separate CDE inputs, use *UAc* and calculate *FV* from

$$FV = UAc * [FV/UA]_{corr}$$

Modeling Method 4

If a point estimate value is generated for the initiator using industry and plant specific event data and used in the PRA, then the corrected *[FV/UA]$_{MAX}$* for a component *C* is calculated from the expression:

$$[FV/UA]_{MAX} = [(FVc + FVie * FVsc)/UAc]$$

Where:

> *FVc* is the Fussell-Vesely for CDF for component *C* as calculated from the PRA Model. This does not include any contribution from initiating events.

> *FVie* is the Fussell-Vesely contribution for the initiating event in question (e.g. loss of service water).

> *FVsc* is the Fussell-Vesely **within the system fault tree only** for component *C* (i.e. the ratio of the sum of the cut sets in the fault tree solution in which that component appears to the overall system failure probability). Note that this may require the construction of a "satellite" system fault tree to arrive at an exact or approximate value for *FVsc* depending on the support system fault tree logic.

FV and UA are separate CDE input values.

F 2. SYSTEM UNRELIABILITY INDEX (URI) DUE TO COMPONENT UNRELIABILITY

Calculation of the URI is performed in three major steps:

- Identification of the monitored components for each system,

- Collection of plant data, and

- Calculation of the URI.

Only the most risk significant components in each system are monitored to minimize the burden for each utility. It is expected that most, if not all the components identified for monitoring are already being monitored for failure reporting to INPO and are also monitored in accordance with the maintenance rule.

F 2.1. IDENTIFY MONITORED COMPONENTS

Monitored Component: A component whose failure to change state or remain running renders the train incapable of performing its monitored functions. In addition, all pumps and diesels in the monitored systems are included as monitored components.

The identification of monitored components involves the use of the system boundaries and success criteria, identification of the components to be monitored within the system boundary and the scope definition for each component. Note that the system boundary defined in section 1.1.1 defines the scope of equipment monitored for unavailability. Only selected components within this boundary are chosen for unreliability monitoring. The first step in identifying these selected components is to identify the system success criteria.

F 2.1.1. SUCCESS CRITERIA

The system boundaries and monitored functions developed in section F 1.1.1 should be used to complete the steps in the following section.

For each system, the monitored functions shall be identified. Success criteria used in the PRA shall then be identified for these functions.

If the licensee has chosen to use success criteria documented in the plant specific PRA that are different from design basis success criteria, examples of plant specific performance factors that should be used to identify the required capability of the train/system to meet the monitored functions are provided below.

- Actuation
  - Time
  - Auto/manual
  - Multiple or sequential
- Success requirements
  - Numbers of components or trains
  - Flows

- o Pressures
- o Heat exchange rates
- o Temperatures
- o Tank water level
- Other mission requirements
- o Run time
- o State/configuration changes during mission
- Accident environment from internal events
- o Pressure, temperature, humidity
- Operational factors
- o Procedures
- o Human actions
- o Training
- o Available externalities (e.g., power supplies, special equipment, etc.)

PRA analyses (e.g. operator action timing requirements) are sometimes based on thermal-hydraulic calculations that account for the best estimate physical capability of a system. These calculations should not be confused with calculations that are intended to establish system success criteria. For example a pump's flow input for PRA thermal-hydraulic calculations may be based on its actual pump curve showing 12,000 gpm at runout while the design basis minimum flow for the pump is 10,000 gpm. The 10,000 gpm value should be used for determination of success or failure of the pump for this indicator. This prevents the scenario of a component or system being operable per Technical Specifications and design basis requirements but unavailable or failed under this indicator.

If the licensee has chosen to use design basis success criteria in the PRA, it is not required to separately document them other than to indicate that is what was used. If success criteria from the PRA are different from the design basis, then the specific differences from the design basis success criteria shall be documented in the basis document.

If success criteria for a system vary by function or initiator, the most restrictive set will be used for the MSPI. Success criteria related to ATWS need not be considered.

F 2.1.2.   SELECTION OF COMPONENTS

For unreliability, use the following process for determining those components that should be monitored. These steps should be applied in the order listed.

1) INCLUDE all pumps (except EDG fuel oil transfer pumps) and diesels.

2) Identify all AOVs, SOVs, HOVs and MOVs that change state to achieve the monitored functions for the system as potential monitored components. Solenoid and Hydraulic valves identified for potential monitoring are only those in the process flow path of a fluid system. Solenoid valves that provide air to AOVs are considered part of the AOV. Hydraulic valves that are control valves for turbine driven pumps are considered part of the pump and are not monitored separately. Check valves and manual valves are not included in the index.

1   a. INCLUDE those valves from the list of valves from step 2 whose failure alone can fail
2   a train. The success criteria used to identify these valves are those identified in the
3   previous section. (See Figure F-5)

4   b. INCLUDE redundant valves from the list of valves from step 2 within a multi-train
5   system, whether in series or parallel, where the failure of both valves would prevent all
6   trains in the system from performing a monitored function. The success criteria used to
7   identify these valves are those identified in the previous section.(See Figure F-5)

8   3) INCLUDE components that cross tie monitored systems between units (i.e. Electrical
9   Breakers and Valves) if they are modeled in the PRA.

10   4) EXCLUDE those valves and breakers from steps 2 and 3 above whose Birnbaum importance,
11   (See section F 2.3.5) as calculated in this appendix (including adjustment for support system
12   initiator, if applicable, and common cause), is less than 1.0E-06. This rule is applied at the
13   discretion of the individual plant. A balance should be considered in applying this rule
14   between the goal to minimize the number of components monitored and having a large
15   enough set of components to have an adequate data pool. If a decision is made to exclude
16   some valves based on low Birnbaum values, but not all, to ensure an adequate data pool, then
17   the valves eliminated from monitoring shall be those with the smallest Birnbaum values.
18   Symmetric valves in different trains should be all eliminated or all retained.

1 **F 2.1.3.**   **DEFINITION OF COMPONENT BOUNDARIES**

2   Table 2 defines the boundaries of components, and Figures F-1, F-2, F-3 and F-4 provide
3   examples of typical component boundaries as described in Table 2.
4
5   **Table 2. Component Boundary Definition**
6

Component	Component boundary
Diesel Generators	The diesel generator boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local), cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, cooling water isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components).
Motor-Driven Pumps	The pump boundary includes the pump body, motor/actuator, lubrication system, cooling components of the pump seals, the voltage supply breaker, and its associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components).
Turbine-Driven Pumps	The turbine-driven pump boundary includes the pump body, turbine/actuator, lubrication system (including pump), extractions, turbo-pump seal, cooling components, and associated control system (relay contacts for normally auto actuated components, control board switches for normally operator actuated components) including the control valve.
Motor-Operated Valves	The valve boundary inc1udes the valve body, motor/actuator, the voltage supply breaker (both motive and control power) and its associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components).
Solenoid Operated Valves	The valve boundary includes the valve body, the operator, the supply breaker (both power and control) or fuse and its associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components).
Hydraulic Operated Valves	The valve boundary includes the valve body, the hydraulic operator, associated local hydraulic system, associated solenoid operated valves, the power supply breaker or fuse for the solenoid valve, and its associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components).
Air-Operated Valves	The valve boundary includes the valve body, the air operator, associated solenoid-operated valve, the power supply breaker or fuse for the solenoid valve, and its associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components.

7
8   For control and motive power, only the last relay, breaker or contactor necessary to power or
9   control the component is included in the monitored component boundary. For example, if an
10 ESFAS signal actuates a MOV, only the relay that receives the ESFAS signal in the control

1 circuitry for the MOV is in the MOV boundary. No other portions of the ESFAS are included.
2 Control switches that provide manual backup for automatically actuated equipment are considered
3 outside the component boundary. Control switches (either in the control room or local) that
4 provide the primary means for actuating a component are monitored as part of the component it
5 actuates. In either case, failure modes of a control switch that render the controlled component
6 unable to perform its function (e.g., prevents auto start of a pump) need to be considered for
7 unavailability of the component.
8
9 Each plant will determine its monitored components and have them available for NRC inspection.
10

11 **F 2.2. COLLECTION OF PLANT DATA**

12 Plant data for the URI includes:
13 • Demands and run hours

14 • Failures

15

16 **F 2.2.1. DEMANDS AND RUN HOURS**

17 *Start demand*: Any demand for the component to successfully start (includes valve and breaker
18 demands to open or close) to perform its monitored functions, actual or test. (Exclude post
19 maintenance test demands, unless in case of a failure the cause of failure was independent of the
20 maintenance performed. In this case the demand may be counted as well as the failure.) The
21 number of demands is:
22 • the number of actual ESF demands plus

23 • the number of estimated test demands plus

24 • the number of estimated operational/alignment demands.

25
26 Best judgment should be used to define each category of demands. But strict segregation of
27 demands between each category is not as important as the validity of total number of demands.
28 The number of estimated demands can be derived based on the number of times a procedure or
29 maintenance activity is performed, or based on historical data over an operating cycle or more. It
30 is also permissible to use the actual number of test and operational demands.
31
32 An update to the estimated demands is required if a change to the basis for the estimated demands
33 results in a >25% change in the estimate of total demands of a group of components within a
34 system. For example, a single MOV in a system may have its estimated demands change by
35 greater than 25%, but revised estimates are not required unless the total number of estimated
36 demands for all MOVs in the system changes by greater than 25%. The new estimate will be used
37 in the calculation the quarter following the input of the updated estimates into CDE. Some
38 monitored valves will include a throttle function as well as open and close functions. One should
39 not include every throttle movement of a valve as a counted demand. Only the initial movement
40 of the valve should be counted as a demand. Demands for valves that do not provide a
41 controlling function are based on a full valve cycle.
42
43

Post maintenance tests: Tests performed following maintenance but prior to declaring the train/component operable, consistent with Maintenance Rule implementation.

Load/Run demand: Applicable to EDG only. Any demand for the EDG output breaker to close, given that the EDG has successfully started and achieved required speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Run Hours: The number of run hours is:

- the number of actual ESF run hours, plus

- the number of estimated test run hours, plus

- the number of estimated operational/alignment run hours.

Best judgment should be used to define each category of run hours. But strict segregation of run hours between the test and operational categories is not as important as the validity of total number of run hours. The number of estimated run hours can be derived based on the number of times a procedure or maintenance activity is performed, or based on historical data over an operating cycle or more. It is also permissible to use the actual number of test and operational run hours. Run hours include the first hour of operation of a component. An update to the estimated run hours is required if a change to the basis for the estimated hours results in a >25% change in the estimate of the total run hours for a group of components in a system. The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE.

F 2.2.2.   FAILURES

In general, a failure of a component for the MSPI is any circumstance when the component is not in a condition to meet the performance requirements defined by the PRA success criteria or mission time for the functions monitored under the MSPI. This is true whether the condition is revealed through a demand or discovered through other means.

Failures for the MSPI are not necessarily equivalent to failures in the maintenance rule. Specifically, the MSPI failure determination does not depend on whether a failure is maintenance preventable. Additionally, the functions monitored for the MSPI are normally a subset of those monitored for the maintenance rule.

EDG failure to start: A failure to start includes those failures up to the point the EDG has achieved required speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to load/run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its monitored functions. This failure mode is treated as a demand failure for calculation purposes. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

1   *EDG failure to run:* Given that it has successfully started and loaded and run for an hour, a failure
2   of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of failure was
3   independent of the maintenance performed.)
4
5   *Pump failure on demand:* A failure to start and run for at least one hour is counted as failure on
6   demand. (Exclude post maintenance tests, unless the cause of failure was independent of the
7   maintenance performed.)
8
9   *Pump failure to run:* Given that it has successfully started and run for an hour, a failure of a pump
10   to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the
11   maintenance performed.)
12
13   *Valve failure on demand*: A failure to transfer to the required monitored state (open, close, or
14   throttle to the desired position as applicable) is counted as failure on demand. (Exclude post
15   maintenance tests, unless the cause of failure was independent of the maintenance performed.)
16
17   *Breaker failure on demand*: A failure to transfer to the required monitored state (open or close as
18   applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of
19   failure was independent of the maintenance performed.)
20
21   <u>Treatment of Demand and Run Failures</u>
22   Failures of monitored components on demand or failures to run, either actual or test are included
23   in unreliability. Failures on demand or failures to run while not critical are included unless an
24   evaluation determines the failure would not have affected the ability of the component to perform
25   its monitored at power function. In no case can a postulated action to recover a failure be used as
26   a justification to exclude a failure from the count.
27
28   <u>Treatment of Discovered Conditions that Result in the Inability to Perform a Monitored Function</u>
29   Discovered conditions of monitored components (conditions within the component boundaries
30   defined in section F 2.1.3) that render a monitored component incapable of performing its
31   monitored function are included in unreliability as a failure, even though no actual failure on
32   demand or while running existed. This treatment accounts for the amount of time that the
33   condition existed prior to discovery, when the component was in an unknown failed state.
34
35   Conditions that render a monitored component incapable of performing its monitored function
36   that are immediately annunciated in the control room without an actual demand occurring are a
37   special case of a discovered condition. In this instance the discovery of the condition is coincident
38   with the failure. This condition is applicable to normally energized control circuits that are
39   associated with monitored components, which annunciate on loss of power to the control circuit.
40   For this circumstance there is no time when the component is in an unknown failed state. In this
41   instance appropriate train unavailable hours will be accounted for, but no additional failure will be
42   counted.
43
44   For other discovered conditions where the discovery of the condition is not coincident with the
45   failure, the appropriate failure mode must be accounted for in the following manner:

- For valves and breakers a demand failure would be assumed and included. An additional demand may also be counted.

- For pumps and diesels, if the discovered condition would have prevented a successful start, a failure is included, but there would be no run time hours or run failure. An additional demand may also be counted.

- For diesels, if it was determined that the diesel would start, but would fail to load (e.g. a condition associated with the output breaker), a load/run failure would be assumed and included. An additional start demand and load/run demand may also be counted.

- For pumps and diesels, if it was determined that the pump/diesel would start and load run, but would fail sometime prior to completing its mission time, a run failure would be assumed. A start demand and a load/run demand would also be assumed and included. The evaluated failure time may be included in run hours.

For a running component that is secured from operation due to observed degraded performance, but prior to failure, then a run failure shall be assumed unless evaluation of the condition shows that the component would have continued to operate for the mission time starting from the time the component was secured.

Unplanned unavailability would accrue in all instances from the time of discovery or annunciation consistent with the definition in section F 1.2.1.

Loss of monitored function(s) is assumed to have occurred if the established success criteria have not been met. If subsequent analysis identifies additional margin for the success criterion, future impacts on URI or UAI for degraded conditions may be determined based on the new criterion. However, the current quarter's URI and UAI must be based on the success criteria of record at the time the degraded condition is discovered. If the new success criteria causes a revision to the PRA affecting the numerical results (i.e. CDF and FV), then the change must be included in the PRA model and the appropriate new values calculated and incorporated in the MSPI Basis Document prior to use in the calculation of URI and UAI. If the change in success criteria has no effect on the numerical results of the PRA (representing only a change in margin) then only the MSPI Basis Document need be revised prior to using the revised success criteria.

If the degraded condition is not addressed by any of the pre-defined success criteria, an engineering evaluation to determine the impact of the degraded condition on the monitored function(s) should be completed and documented. The use of component failure analysis, circuit analysis, or event investigations is acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the impact of the degraded condition on the monitored function. The engineering evaluation should be completed as soon as practical. If it cannot be completed in time to support submission of the PI report for the current quarter, the comment field shall note that an evaluation is pending. The evaluation must be completed in time to accurately account for unavailability/unreliability in the next quarterly report. Exceptions to this guidance are expected to be rare and will be treated on a case-by-case basis.
Licensees should identify these situations to the resident inspector.

1 <u>Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components</u>
2 <u>(SSC)</u>
3 Failures of SSC's that are not included in the performance index will not be counted as a failure
4 or a demand. Failures of SSC's that would have caused an SSC within the scope of the
5 performance index to fail will not be counted as a failure or demand. An example could be a
6 manual suction isolation valve left closed which would have caused a pump to fail. This would
7 not be counted as a failure of the pump. Any mis-positioning of the valve that caused the train to
8 be unavailable would be counted as unavailability from the time of discovery. The significance of
9 the mis-positioned valve prior to discovery would be addressed through the inspection process.
10 (Note, however, in the above example, if the shut manual suction isolation valve resulted in an
11 actual pump failure, the pump failure would be counted as a demand and failure of the pump.)

F 2.3. CALCULATION OF URI

Unreliability is monitored at the component level and calculated at the system level. URI is proportional to the weighted difference between the plant specific component unreliability and the industry average unreliability. The Birnbaum importance is the weighting factor. Calculation of system URI due to this difference in component unreliability is as follows:

$$URI = \sum_{j=1}^{m} \begin{bmatrix} B_{Dj}(UR_{DBCj} - UR_{DBLj}) \\ + B_{Lj}(UR_{LBCj} - UR_{LBLj}) \\ + B_{Rj}(UR_{RBCj} - UR_{RBLj}) \end{bmatrix} \qquad \text{Eq. 3}$$

Where the summation is over the number of monitored components (m) in the system, and:

B_{Dj}, B_{Lj} and B_{Rj} are the Birnbaum importance measures for the failure modes fail on demand, fail to load and fail to run respectively,

UR_{DBC}, UR_{LBC}, and UR_{RBC} are Bayesian corrected plant specific values of unreliability for the failure modes fail on demand, fail to load and fail to run respectively, and

UR_{DBL}, UR_{LBL}, and UR_{RBL} are Baseline values of unreliability for the failure modes fail on demand, fail to load and fail to run respectively.

The Birnbaum importance for each specific component failure mode is defined as

$$B = CDF_p \left[\frac{FV_{URc}}{UR_{pc}} \right]_{MAX} \qquad \text{Eq. 4}$$

Where,

CDF_p is the plant-specific internal events, at power, core damage frequency,

FV_{URc} is the component and failure mode specific Fussell-Vesely value for unreliability,

UR_{Pc} is the plant-specific PRA value of component and failure mode unreliability,

Failure modes defined for each component type are provided below. There may be several basic events in a PRA that correspond to each of these failure modes used to collect plant specific data. These failure modes are used to define how the actual failures in the plant are categorized.

Valves and Breakers:
Fail on Demand (Open/Close)

Pumps:
Fail on Demand (Start)
Fail to Run

Emergency Diesel Generators:
Fail on Demand (Start)
Fail to Load/Run
Fail to Run

1   A method for calculation of the quantities in equation 3 and 4 from importance measures
2   calculated using cutsets from an existing PRA solution is discussed in sections F 2.3.1 through F
3   2.3.3.
4
5   An alternate approach, based on re-quantification of the PRA model, and calculation of the
6   importance measures from first principles is also an acceptable method. Guidance on this alternate
7   method is contained in section 6 of this appendix. A plant using this alternate approach should use
8   the guidance in section 6 and skip sections F 2.3.1 through F 2.3.3.
9

10   **F 2.3.1. TRUNCATION LEVELS**

11   The values of importance measures calculated using an existing cutset solution are influenced by
12   the truncation level of the solution. The truncation level chosen for the solution should be 7 orders
13   of magnitude less than the baseline CDF for the alternative defined in sections F 2.3.2 and F
14   2.3.3.
15

16   As an alternative to using this truncation level, the following sensitivity study may be performed
17   to establish the acceptability of a higher (e.g. 6 orders of magnitude) truncation level.
18

19   1. Solve the model at the truncation level you intend to use. (e.g. 6 orders of magnitude
20   below the baseline CDF)
21   2. Identify the limiting Birnbaum value for each component. (this is the case 1 value)
22   3. Solve the model again with a truncation 10 times larger (e.g.. 5 orders of magnitude below
23   the baseline CDF)
24   4. Identify the limiting Birnbaum value for each component. (this is the case 2 value)
25   5. For each component with Birnbaum-case 1 greater than 1.0E-06 calculate the ratio
26   [(Birnbaum-case 2)/(Birnbaum-case 1)]
27   6. If the value for the calculated ratio is greater than 0.8 for all components with Birnbaum-
28   case 1 value greater than 1.0E-06, then the case 1 truncation level may be used for this
29   analysis.
30

31   This process may need to be repeated several times with successively lower truncation levels to
32   achieve acceptable results.
33

34   **F 2.3.2.   CALCULATION OF CORE DAMAGE FREQUENCY (CDFP)**

35   The Core Damage Frequency is a CDE input value. The required value is the <u>internal events</u>
36   average maintenance at power value. Internal flooding and fire are not included in this calculated
37   value. In general, all inputs to this indicator from the PRA are calculated from the internal events
38   model only.
39

40   **F 2.3.3.   CALCULATION OF [FV/UR]MAX**

41   The FV, UR and common cause adjustment values developed in this section are separate CDE
42   input values.
43

44   Equation 4 includes a term that is the ratio of a Fussell-Vesely importance value divided by the
45   related unreliability. The calculation of this ratio is performed in a similar manner to the ratio

calculated for UAI, except that the ratio is calculated for each monitored component. One additional factor needs to be accounted for in the unreliability ratio that was not needed in the unavailability ratio, the contribution to the ratio from common cause failure events. The discussion in this section will start with the calculation of the initial ratio and then proceed with directions for adjusting this value to account for the cooling water initiator contribution, as in the unavailability index, and then the common cause correction.

It can be shown that for a given component represented by multiple basic events, the ratio of the two values for the component is equal to the ratio of values for any basic event representing the component. Or,

$$\frac{FVbe}{URbe} = \frac{FVURc}{URPc} = \text{Constant}$$

as long as the basic events under consideration are logically equivalent.

Note that the constant value may be different for the unreliability ratio and the unavailability ratio because the two types of events are frequently not logically equivalent. For example recovery actions may be modeled in the PRA for one but not the other. This ratio may also be different for fail on demand and fail to run events for the same component. This is particularly true for cooling water pumps that have a trip initiation function as well as a mitigation function.

There are two options for determining the initial value of this ratio: The first option is to identify one maximum ratio that will be used for all applicable failure modes for the component. The second option is to identify a separate ratio for each failure mode for the component. These two options will be discussed next.

Option 1
Identify one maximum ratio that will be used for all applicable failure modes for the component. The process for determining a single value of this ratio for all failure modes of a component is to identify all basic events that fail the component (excluding common cause events and test and maintenance events). It is typical, given the component scope definitions in Table 2, that there will be several plant components modeled separately in the plant PRA that make up the MSPI component definition. For example, it is common that in modeling an MOV, the actuation relay for the MOV and the power supply breaker for the MOV are separate components in the plant PRA. Ensure that the basic events related to all of these individual components are considered when choosing the appropriate *[FV/UR]* ratio.

Determine the failure probabilities for the events, determine the associated FV values for the events and then calculate the ratios, *[FV/UR]$_{ind}$*, where the subscript refers to independent failures. Choose from this list the basic event for the component and its associated FV value that results in the largest *[FV/UR]* ratio. This will typically be the event with the largest failure probability to minimize the effects of truncation on the calculation.

1 *Option 2*
2 Identify a separate ratio for each failure mode for the component The process for determining a
3 ratio value for each failure mode proceeds similarly by first identifying all basic events related to
4 each component. After this step, each basic event must be associated with one of the specific
5 defined failure modes for the component. Proceed as in option 1 to find the values that result in
6 the largest ratio for each failure mode for the component. In this option the CDE inputs will
7 include FV and UR values for each failure mode of the component.
8
9 **F 2.3.4.   CORRECTIONS TO FV/UR RATIO**
10
11 Treatment of PRA Modeling Asymmetries
12 In systems with rotated normally running pumps (e. g. cooling water systems), the PRA models
13 may assume one pump is always the running and another is in standby. For example, a service
14 water system may have two 100% capacity pumps in one train, an A and B pump. In practice the
15 A and B pumps are rotated and each one is the running pump 50% of the time. In the PRA model
16 however, the A pump is assumed to be always running and the B pump is always in assumed to
17 be in standby. This will result in one pump appearing to be more important than the other when
18 they are, in fact, of equal importance. This asymmetry in importance is driven by the assumption
19 in the PRA, not the design of the plant.
20
21 When this is encountered, the importance measures may be used as they are calculated from the
22 PRA model for the component importance used in the calculation of URI. Although these are not
23 actually the correct importance values, the method used to calculate URI will still provide the
24 correct result because the same value of unreliability is used for each component as a result of the
25 data being pooled. Note that this is different from the treatment of importance in the calculation of
26 UAI.
27
28 Cooling Water and Service Water System [FV/UR]ind Values
29 Ensure that the correction term in this section is applied prior to the calculation of the common
30 cause correction in the next section. Component Cooling Water Systems (CCW) and Service
31 Water Systems (SWS) at some nuclear stations contribute to risk in two ways. First, the systems
32 provide cooling to equipment used for the mitigation of events and second, the failures in the
33 systems may also result in the initiation of an event. Depending on the manner in which the
34 initiator contribution is treated in the PRA, it may be necessary to apply a correction to the
35 FV/UR ratio calculated in the section above.
36 The correction must be applied to each FV/UR ratio used for this index. If the option to use
37 separate ratios for each component failure mode was used in the section above then this correction
38 is calculated for each failure mode of the component.
39
40 The contribution to risk from failures to provide cooling to other plant equipment is modeled
41 directly through dependencies in the PRA model. However, the contribution due to event
42 initiation is treated in four general ways in current PRAs:
43 1)   The use of linked initiating event fault trees for these systems with the same basic
44   events used in the initiator and mitigation trees.
45 2)   The use of linked initiating event fault trees for these systems with different basic
46   events used in the initiator and mitigation trees.

1 3) Fault tree solutions are generated for these systems external to the PRA and the
2   calculated value is used in the PRA as a point estimate
3 4) A point estimate value is generated for the initiator using industry and plant specific
4   event data and used in the PRA.
5
6 Each of these methods is discussed below.
7
8 *Modeling Method 1*
9 If a PRA uses the first modeling option, then the FV values calculated will reflect the total
10 contribution to risk for a component in the system. No additional correction to the FV values is
11 required.
12
13 *Modeling Methods 2 and 3*
14 The corrected ratio may be calculated as described for modeling method 4 or by the method
15 described below.
16
17 If a linked initiating event fault tree with different basic events used in the initiator and mitigation
18 trees is the modeling approach taken, or fault tree solutions are generated for these systems
19 external to the PRA and the calculated value is used in the PRA as a point estimate, then the
20 corrected ratio is given by:

21
$$[FV/UR]_{corr} = \left[\frac{FVc}{URc} + \sum_{m=1}^{i} \left\{ \frac{IE_{m,n}(1) - IE_{m,n}(0)}{IE_{m,n}(q_n)} * FVie_m \right\} \right].$$

22
23 In this expression the summation is taken over all system initiators *i* that involve component *n*,
24 where
25   *FVc* is the Fussell-Vesely for component *C* as calculated from the PRA Model. This does
26   not include any contribution from initiating events,
27   *URc* is the basic event unreliability used in computing *FVc*; i.e. in the system response
28   models,
29      $IE_{m,n}(q_n)$ is the system initiator frequency of initiating event *m* when the component *n*
30   unreliability basic event is q_n. The event chosen in the initiator tree should represent the
31   same failure mode for the component as the event chosen for URc,
32      $IE_{m,n}(1)$ is as above but $q_n=1$,
33      $IE_{m,n}(0)$ is as above but $q_n=0$
34   and
35      $FVie_m$ is the Fussell-Vesely importance contribution for the initiating event *m* to the CDF.
36
37 Since *FV* and *UR* are separate CDE inputs, use *URc* and calculate *FV* from
38      $$FV = URc * [FV/UR]_{corr}$$
39
40 *Modeling Method 4*
41 If a point estimate value is generated for the initiator using industry and plant specific event data
42 and used in the PRA, then the corrected *[FV/UR]$_{MAX}$* for a component *C* is calculated from the
43 expression:
44      $$[FV/UR]_{MAX} = [(FVc + FVie * FVsc)/URc]$$

Where:

    FVc is the Fussell-Vesely for CDF for component *C* as calculated from the PRA Model. This does not include any contribution from initiating events.

    FVie is the Fussell-Vesely contribution for the initiating event in question (e.g. loss of service water).

    FVsc is the Fussell-Vesely **within the system fault tree only** for component *C* (i.e. the ratio of the sum of the cut sets in the fault tree solution in which that component appears to the overall system failure probability). Note that this may require the construction of a "satellite" system fault tree to arrive at an exact or approximate value for *FVsc* depending on the support system fault tree logic.

FV and UR are separate CDE input values.

Including the Effect of Common Cause in [FV/UR]max

Be sure that the correction factors from the previous section are applied prior to the common cause correction factor being calculated.

Changes in the independent failure probability of an SSC imply a proportional change in the common cause failure probability, even though no actual common cause failures have occurred. The impact of this effect on URI is considered by including a multiplicative adjustment to the [FV/UR]$_{ind}$ ratio developed in the section above. This multiplicative factor (A) is entered into CDE as "CCF."

Two methods are provided for including this effect, a simple generic approach that uses bounding generic adjustment values and a more accurate plant specific method that uses values derived from the plant specific PRA. Different methods can be used for different systems. However, within an MSPI system, either the generic or plant specific method must be used for all components in the system, not a combination of different methods. For the cooling water system, different methods may be used for the subsystems that make up the cooling water system. For example, component cooling water and service water may use different methods.

The common cause correction factor is only applied to components within a system and does not include cross system (such as between the BWR HPCI and RCIC systems) common cause. If there is only one component within a component type within the system, the adjustment value is 1.0. Also, if all components within a component type are required for success, then the adjustment value is 1.0.

Generic CCF Adjustment Values

Generic values have been developed for monitored components that are subject to common cause failure. The correction factor is used as a multiplier on the [FV/UR] ratio for each component in the common cause group. This method may be used for simplicity and is recommended for components that are less significant contributors to the URI (e.g. [FV/UR] is small). The multipliers are provided in table 3.

1 The EDG is a "super-component" that includes valves, pumps and breakers within the super-
2 component boundary. The EDG generic adjustment value should be applied to the EDG "super-
3 component" even if the specific event used for the [FV/UR] ratio for the EDG is a valve or
4 breaker failure.

1
2

Table 3. Generic CCF Adjustment Values

	EPS	HPI		HRS/		RHR
	EDG	MDP Running or Alternating[+]	MDP Standby	MDP Standby	TDP **	MDP Standby
Arkansas 1	1.25	2	1	1	1	1.5
Arkansas 2	1.25	1	2	1	1	1.5
Beaver Valley 1	1.25	2	1	1.25	1	1.5
Beaver Valley 2	1.25	2	1	1.25	1	1.5
Braidwood 1 & 2	3	1.25	1.25	1	1	1.5
Browns Ferry 2	1.25	1	1	1	1	3
Browns Ferry 3	1.25	1	1	1	1	3
Brunswick 1 & 2	1.25	1	1	1	1	3
Byron 1 & 2	3	1.25	1.25	1	1	1.5
Callaway	1.25	1.25	1.25	1.25	1	1.5
Calvert Cliffs 1 & 2	1.25	1	2	1.25	1.5	1.5
Catawba 1 & 2	1.25	1.25	1.25	1.25	1	1.5
Clinton 1	1.25	1	1	1	1	1.5
Columbia Nuclear	1.25	1	1	1	1	1.5
Comanche Peak 1 & 2	1.25	1.25	1.25	1.25	1	1.5
Cook 1 & 2	1.25	1.25	1.25	1.25	1	1.5
Cooper Station	1.25	1	1	1	1	3
Crystal River 3	1.25	2	1	1	1	1.5
Davis-Besse	1.25	1.25	1.25	1	1.5	1.5
Diablo Canyon 1 & 2	2	1.25	1.25	1.25	1	1.5
Dresden 2 & 3	1.25	3	1	1	1	3
Duane Arnold	1.25	1	1	1	1	3
Farley 1 & 2	2	2	1	1.25	1	1.5
Fermi 2	1.25	1	1	1	1	3
Fitzpatrick	3	1	1	1	1	3
Fort Calhoun	1.25	1	2	1	1	1.5
Ginna	1.25	1	2	1.25	1	1.5
Grand Gulf	1.25	1	1	1	1	1.5
Harris	1.25	2	1	1.25	1	1.5
Hatch 1 & 2	2	1	1	1	1	3
Hope Creek	1.25	1	1	1	1	1.5
Indian Point 2	1.25	1	2	1.25	1	1.5
Indian Point 3	1.25	1	2	1.25	1	1.5
Kewaunee	1.25	1	1.25	1.25	1	1.5
LaSalle 1 & 2	1.25	1	1	1	1	1.5
Limerick 1 & 2	3	1	1	1	1	3
McGuire 1 & 2	1.25	1.25	1.25	1.25	1	1.5
Millstone 2	1.25	1	2	1.25	1	1.5
Millstone 3	1.25	2	1.25	1.25	1	1.5
Monticello	1.25	1	1	1	1	3
Nine Mile Point 1	1.25	3	1	1	1	3
Nine Mile Point 2	1.25	1	1	1	1	1.5

	EPS	HPI		HRS/		RHR
	EDG	MDP Running or Alternating[+]	MDP Standby	MDP Standby	TDP **	MDP Standby
North Anna 1 & 2	1.25	2	1	1.25	1	1.5
Oconee 1, 2 & 3	3 *	2	1	1.25	1	1.5
Oyster Creek	1.25	1	3	1	1	3
Palisades	1.25	1	1.25	1.25	1	1.5
Palo Verde 1, 2 & 3	1.25	1	1.25	1.25	1	1.5
Peach Bottom 2 & 3	1.25	1	1	1	1	3
Perry	1.25	1	1	1	1	1.5
Pilgrim	1.25	1	1	1	1	3
Point Beach 1 & 2	1.25	1	1.25	1.25	1	1.5
Prairie Island 1 & 2	1.25	1	1.25	1	1	1.5
Quad Cities 1 & 2	1.25	1	1	1	1	3
River Bend	1.25	1	1	1	1	1.5
Robinson 2	1.25	1	1.25	1.25	1	1.5
Salem 1 & 2	1.25	1.25	1.25	1.25	1	1.5
San Onofre 2 & 3	1.25	1	2	1.25	1	1.5
Seabrook	1.25	1.25	1.25	1	1	1.5
Sequoyah 1 & 2	1.25	1.25	1.25	1.25	1	1.5
South Texas 1 & 2	2	1	2	2	1	1.5
St. Lucie 1	1.25	1	1.25	1.25	1	1.5
St. Lucie 2	1.25	1	1.25	1.25	1	1.5
Summer	1.25	2	1	1.25	1	1.5
Surry 1 & 2	1.25	2	1	1.25	1	1.5
Susquehanna 1 & 2	3	1	1	1	1	3
Three Mile Island 1	1.25	2	1	1.25	1	1.5
Turkey Point 3 & 4	1.25	1	3	1	3	1.5
Vermont Yankee	1.25	1	1	1	1	3
Vogtle 1 & 2	1.25	1.25	1.25	1.25	1	1.5
Waterford 3	1.25	1	2	1.25	1	1.5
Watts Bar 1	1.25	1.25	1.25	1.25	1	1.5
Wolf Creek	1.25	1.25	1.25	1.25	1	1.5

1 * hydroelectric units   ** as applicable
2 [+] Alternating pumps are redundant pumps where one pump is normally running, that are
3 operationally rotated on a periodic basis.
4

	SWS			CCW		All	All
	MDP Running or Alternating	MDP Standby	DDP **	MDP Running or Alternating	MDP Standby	MOVs and Breakers	AOVs, SOVs, HOVs
All Plants	3	1.5	1.25	1.5	2	2	1.5

5 ** as applicable
6

1 <u>Plant Specific Common Cause Adjustment</u>
2 The plant specific correction factor should be calculated for each FV/UR ratio that is used in the
3 index. If the option to use a different ratio for each failure mode of a component is used, then the
4 ratio is calculated for each failure mode. The general form of a plant specific common cause
5 adjustment factor is given by the equation:

6
$$A = \frac{\left[\left(\sum_{i=1}^{n} FV_i\right) + FV_{cc}\right]}{\sum_{i=1}^{n} FV_i}.$$
Eq. 5

7 Where:
8   n = is the number of components in a common cause group,
9   FV_i = the FV for independent failure of component i,
10   and
11   FV_{cc} = the FV for the common cause failure of components in the group.
12
13 In the expression above, the FV_i are the values for the specific failure mode for the component
14 group that was chosen because it resulted in the maximum *[FV/UR]* ratio. The FV_{cc} is the FV that
15 corresponds to all combinations of common cause events for that group of components for the
16 same specific failure mode. Note that the FV_{cc} may be a sum of individual FV_{cc} values that
17 represent different combinations of component failures in a common cause group.
18
19 For cooling water systems that have an initiator contribution, the FV values used should be from
20 the non-initiator part of the model.
21
22 For example consider again a plant with three one hundred percent capacity emergency diesel
23 generators. In this example, three failure modes for the EDG are modeled in the PRA, fail to start
24 (FTS), fail to load (FTL) and fail to run (FTR). Common cause events exist for each of the three
25 failure modes of the EDG in the following combinations:
26   1)   Failure of all three EDGs,
27   2)   Failure of EDG-A and EDG-B,
28   3)   Failure of EDG-A and EDG-C,
29   4)   Failure of EDG-B and EDG-C.
30 This results in a total of 12 common cause events.
31
32 Assume the maximum [FV/UR] resulted from the FTS failure mode, then the FV_{cc} used in
33 equation 5 would be the sum of the four common cause FTS events for the combinations listed
34 above.
35
36 It is recognized that there is significant variation in the methods used to model common cause. It
37 is common that the 12 individual common cause events described above are combined into a
38 fewer number of events in many PRAs. Correct application of the plant specific method would, in
39 this case, require the decomposition of the combined events and their related FV values into the
40 individual parts. This can be accomplished by application of the following proportionality:

$$FVpart = FVtotal \times \frac{URpart}{URtotal} \qquad\qquad\qquad \text{Eq. 6}$$

Returning to the example above, assume that common cause was modeled in the PRA by combining all failure modes for each specific combination of equipment modeled. Thus there would be four common cause events corresponding to the four possible equipment groupings listed above, but each of the common cause events would include the three failure modes FTS, FTL and FTR. Again, assume the FTS independent failure mode is the event that resulted in the maximum [FV/UR] ratio. The FVcc value to be used would be determined by determining the FTS contribution for each of the four common cause events. In the case of the event representing failure of all three EDGs this would be determined from

$$FVFTSABC = FVABC \times \frac{URFTSABC}{URABC} \; .$$

Where,

   FV_{FTSABC} = the FV for the FTS failure mode and the failure of all three EDGs
   FV_{ABC} = the event from the PRA representing the failure of all three EDGs due to all
   failure modes
   UR_{FTSABC} = the failure probability for a FTS of all three EDGs, and
   UR_{ABC} = the failure probability for all failure modes for the failure of all three EDGs.

After this same calculation was performed for the remaining three common cause events, the value for FV_{CC} to be used in equation 5 would then be calculated from:
   $$FVcc = FVFTSABC + FVFTSAB + FVFTSAC + FVFTSBC$$

This value is used in equation 5 to determine the value of *A*. The final quantity used in equation 4 is given by:
   $$[FV/UR]\max \; = \; A*[FV/UR]ind$$

In this case the individual values on the right hand side of the equation above are input to CDE.

F 2.3.5.   BIRNBAUM IMPORTANCE

One of the rules used for determining the valves and circuit breakers to be monitored in this performance indicator permitted the exclusion of valves and circuit breakers with a Birnbaum importance less than 1.0E-06. To apply this screening rule the Birnbaum importance is calculated from the values derived in this section as:

   $$B = CDF*A*[FV/UR]_{ind} = CDF*[FV/UR]_{max}$$

Ensure that the support system initiator correction (if applicable) and the common cause correction are included in the Birnbaum value used to exclude components from monitoring.

1 **F 2.3.6.   CALCULATION OF UR_{DBC}, UR_{LBC} AND UR_{RBC}**

2 Equation 3 includes the three quantities UR_{DBC}, UR_{LBC} and UR_{RBC} which are the Bayesian
3 corrected plant specific values of unreliability for the failure modes fail on demand, fail to load
4 and fail to run respectively. This section discusses the calculation of these values. As discussed in
5 section F 2.3 failure modes considered for each component type are provided below.

6
7   Valves and Breakers:
8   Fail on Demand (Open/Close)

9   Pumps:
10   Fail on Demand (Start)
11   Fail to Run

12   Emergency Diesel Generators:
13   Fail on Demand (Start)
14   Fail to Load/Run
15   Fail to Run

16
17 UR_{DBC} is calculated as follows.[15]

18
$$UR_{DBC} = \frac{(N_d + a)}{(a + b + D)}.$$
Eq. 7

19 where in this expression:
20   N_d is the total number of failures on demand during the previous 12 quarters,
21   D is the total number of demands during the previous 12 quarters determined in
22   section 2.2.1
23   The values a and b are parameters of the industry prior, derived from industry
24   experience (see Table 4).

25
26 In the calculation of equation 7 the numbers of demands and failures is the sum of all demands
27 and failures for similar components within each system. Do not sum across units for a multi-unit
28 plant. For example, for a plant with two trains of Emergency Diesel Generators, the demands and
29 failures for both trains would be added together for one evaluation of equation 7 which would be
30 used for both trains of EDGs.

31
32 UR_{LBC} is calculated as follows.

33
$$UR_{LBC} = \frac{(N_l + a)}{(a + b + D)}.$$
Eq. 8

34
35 where in this expression:
36   N_l is the total number of failures to load (applicable to EDG only) during the
37   previous 12 quarters,
38   D is the total number of load demands during the previous 12 quarters determined
39   in section 2.2.1

---

[15] Atwood, Corwin L., Constrained noninformative priors in risk assessment, *Reliability Engineering and System Safety*, 53 (1996; 37-46)

The values *a* and *b* are parameters of the industry prior, derived from industry experience (see Table 4).

In the calculation of equation 8 the numbers of demands and failures is the sum of all demands and failures for similar components within each system.

UR_{RBC} is calculated as follows.

$$UR_{RBC} = \frac{(N_r + a)}{(T_r + b)} * T_m \qquad \text{Eq. 9}$$

where:

N_r is the total number of failures to run during the previous 12 quarters (determined in section 2.2.2),

T_r is the total number of run hours during the previous 12 quarters (determined in section 2.2.1)

T_m is the mission time for the component based on plant specific PRA model assumptions. Where there is more than one mission time for different initiating events or sequences (e.g., turbine-driven AFW pump for loss of offsite power with recovery versus loss of feedwater), the longest mission time is to be used. and

a and *b* are parameters of the industry prior, derived from industry experience (see Table 4).

In the calculation of equation 9 the numbers of demands and run hours is the sum of all run hours and failures for similar components within each system. Do not sum across units for a multi-unit plant. For example, a plant with two trains of Emergency Diesel Generators, the run hours and failures for both trains would be added together for one evaluation of equation 9 which would be used for both trains of EDGs.

1
2 **F 2.3.7.   BASELINE UNRELIABILITY VALUES**

3   The baseline values for unreliability are contained in Table 4 and remain fixed.
4
5   **Table 4. Industry Priors and Parameters for Unreliability**
6

Component	Failure Mode	a [a]	b [a]	Industry MeanValue [b] URBLC
Circuit Breaker	Fail to open (or close)	4.99E-1	6.23E+2	8.00E-4
Hydraulic-operated valve	Fail to open (or close)	4.98E-1	4.98E+2	1.00E-3
Motor-operated valve	Fail to open (or close)	4.99E-1	7.12E+2	7.00E-4
Solenoid-operated valve	Fail to open (or close)	4.98E-1	4.98E+2	1.00E-3
Air-operated valve	Fail to open (or close)	4.98E-1	4.98E+2	1.00E-3
Motor-driven pump, standby	Fail to start	4.97E-1	2.61E+2	1.90E-3
	Fail to run	5.00E-1	1.00E+4	5.00E-5
Motor-driven pump, running or alternating	Fail to start	4.98E-1	4.98E+2	1.00E-3
	Fail to run	5.00E-1	1.00E+5	5.00E-6
Turbine-driven pump, AFWS	Fail to start	4.85E-1	5.33E+1	9.00E-3
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Turbine-driven pump, HPCI or RCIC	Fail to start	4.78E-1	3.63E+1	1.30E-2
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Diesel-driven pump, AFWS	Fail to start	4.80E-1	3.95E+1	1.20E-2
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Emergency diesel generator	Fail to start	4.92E-1	9.79E+1	5.00E-3
	Fail to load/run	4.95E-1	1.64E+2	3.00E-3
	Fail to run	5.00E-1	6.25E+2	8.00E-4

7
8   a. A constrained, non-informative prior is assumed. For failure to run events, a = 0.5 and b =
9   (a)/(mean rate). For failure upon demand events, a is a function of the mean probability:
10

Mean Probability	a
0.0 to 0.0025	0.50
>0.0025 to 0.010	0.49
>0.010 to 0.016	0.48
>0.016 to 0.023	0.47
>0.023 to 0.027	0.46

11
12   Then b = (a)(1.0 - mean probability)/(mean probability).
13
14   b. Failure to run events occurring within the first hour of operation are included within the fail to
15   start failure mode. Failure to run events occurring after the first hour of operation are
16   included within the fail to run failure mode.

F 3. ESTABLISHING STATISTICAL SIGNIFICANCE

This performance indicator establishes an acceptable level of performance for the monitored systems that is reflected in the baseline reliability values in Table 4. Plant specific differences from this acceptable performance are interpreted in the context of the risk significance of the difference from the acceptable performance level. It is expected that a system that is performing at an acceptable performance level will see variations in performance over the monitoring period. For example a system may, on average, see three failures in a three year period at the accepted level of reliability. It is expected, due to normal performance variation, that this system will sometimes experience two or four failures in a three year period. It is not appropriate that a system should be placed in a white performance band due to expected variation in measured performance. This problem is most noticeable for risk sensitive systems that have few demands in the three year monitoring period.

This problem is resolved by applying a limit of 5.0E-07 to the magnitude of the most significant failure in a system. This ensures that one failure beyond the expected number of failures alone cannot result in MSPI > 1.0E-06. A MSPI > 1.0E-06 will still be a possible result if there is significant system unavailability, or failures in other components in the system.

This limit on the maximum value of the most significant failure in a system is only applied if the MSPI value calculated without the application of the limit is less than 1.0E-05.
This calculation will be performed by the CDE software; no additional input values are required.

F 4. CALCULATION OF SYSTEM COMPONENT PERFORMANCE LIMITS

The mitigating systems chosen to be monitored are generally the most important systems in nuclear power stations. However, in some cases the system may not be as important at a specific station. This is generally due to specific features at a plant, such as diverse methods of achieving the same function as the monitored system. In these cases a significant degradation in performance could occur before the risk significance reached a point where the MSPI would cross the white boundary. In cases such as this it is not likely that the performance degradation would be limited to that one system and may well involve cross cutting issues that would potentially affect the performance of other mitigating systems.
A performance based criterion for determining declining performance is used as an additional decision criterion for determining that performance of a mitigating system has degraded to the white band. This decision is based on deviation of system performance from expected performance. The decision criterion was developed such that a system is placed in the white performance band when there is high confidence that system performance has degraded even though MSPI < 1.0E-06.

The criterion is applied to each component type in a system. If the number of failures in a 36 month period for a component type exceeds a performance based limit, then the system is considered to be performing at a white level, regardless of the MSPI calculated value. The performance based limit is calculated in two steps:
1. Determine the expected number of failures for a component type and
2. Calculate the performance limit from this value.

1 The expected number of failures is calculated from the relation
2      $$Fe = Nd * p + \lambda * Tr$$
3 Where:
4   N_d is the number of demands
5   p is the probability of failure on demand, from Table 4.
6   λ is the failure rate, from Table 4.
7   T_r is the runtime of the component
8
9 This value is used in the following expression to determine the maximum number of failures:
10     $$Fm = 4.65 * Fe + 4.2$$
11
12 If the actual number of failures (Fa) of a similar group of components (components that are
13 grouped for the purpose of pooling data) within a system in a 36 month period exceeds Fm, then
14 the system is placed in the white performance band or the level dictated by the MSPI calculation
15 if the MSPI calculation is > 1E-5.
16
17 This calculation will be performed by the CDE software, no additional input values are required.
18
19 **F 5. ADDITIONAL GUIDANCE FOR SPECIFIC SYSTEMS**
20 This section identifies the potential monitored functions for each system and describes typical
21 system scopes and train determinations.
22
23 **Emergency AC Power Systems**
24
25 **Scope**
26 The function monitored for the emergency AC power system is the ability of the emergency
27 generators to provide AC power to the class 1E buses following a loss of off-site power. The
28 emergency AC power system is typically comprised of two or more independent emergency
29 generators that provide AC power to class 1E buses following a loss of off-site power. The
30 emergency generator dedicated to providing AC power to the high pressure core spray system in
31 BWRs is not within the scope of emergency AC power.
32
33 The EDG **component** boundary includes the generator body, generator actuator, lubrication
34 system (local), fuel system (local or day tank), cooling components (local), startup air system
35 receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the
36 normal DC distribution system), individual diesel generator control system, cooling water
37 isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit.
38 Air compressors are not part of the EDG **component** boundary.
39
40 The fuel transfer pumps required to meet the PRA mission time are within the **system** boundary,
41 but are not considered to be a monitored component for reliability monitoring in the EDG system.
42 Additionally they are monitored for contribution to train unavailability only if an EDG train can
43 only be supplied from a single transfer pump. Where the capability exists to supply an EDG from
44 redundant transfer pumps, the contribution to the EDG MSPI from these components is expected
45 to be small compared to the contribution from the EDG itself. Monitoring the transfer pumps for
46 reliability is not practical because accurate estimations of demands and run hours are not feasible

(due to the auto start and stop feature of the pump) considering the expected small contribution to the index.

Emergency generators that are not safety grade, or that serve a backup role only (e.g., an alternate AC power source), are not included in the performance reporting.

Train Determination

The number of emergency AC power system trains for a unit is equal to the number of class 1E emergency generators that are available to power safe-shutdown loads in the event of a loss of off-site power for that unit. There are three typical configurations for EDGs at a multi-unit station:

1. EDGs dedicated to only one unit.

2. One or more EDGs are available to "swing" to either unit

3. All EDGs can supply all units

For configuration 1, the number of trains for a unit is equal to the number of EDGs dedicated to the unit. For configuration 2, the number of trains for a unit is equal to the number of dedicated EDGs for that unit plus the number of "swing" EDGs available to that unit (i.e., The "swing" EDGs are included in the train count for each unit). For configuration 3, the number of trains is equal to the number of EDGs.

Clarifying Notes

The emergency diesel generators are not considered to be available during the following portions of periodic surveillance tests unless recovery from the test configuration during accident conditions is virtually certain, as described in "Credit for operator recovery actions during testing," can be satisfied; or the duration of the condition is less than fifteen minutes per train at one time:

- Load-run testing

- Barring

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event

- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)

- failure to start because a redundant portion of the starting system was intentionally disabled for test purposes, if followed by a successful start with the starting system in its normal alignment

1   **BWR High Pressure Injection Systems**
2
3   **(High Pressure Coolant Injection, High Pressure Core Spray, and Feedwater Coolant**
4   **Injection)**
5
6   **Scope**
7   These systems function at high pressure to maintain reactor coolant inventory and to remove
8   decay heat.
9
10   The function monitored for the indicator is the ability of the monitored system to take suction
11   from the suppression pool (and from the condensate storage tank, if required to meet the PRA
12   success criteria and mission times) and inject into the reactor vessel. . The mitigation of ATWS
13   events with a high pressure injection system is not considered a function to be monitored by the
14   MSPI. (Note, however, that the FV values will include ATWS events).
15
16   Plants should monitor either the high-pressure coolant injection (HPCI), the high-pressure core
17   spray (HPCS), or the feedwater coolant injection (FWCI) system, whichever is installed. The
18   turbine and governor and associated piping and valves for turbine steam supply and exhaust are
19   within the scope of the HPCI system. The flow path for the steam supply to a turbine driven pump
20   is included from the steam source (main steam lines) to the pump turbine. The motor driven pump
21   for HPCS and FWCI are in scope along with any valves that must change state such as low flow
22   valves in FWCI. Valves in the feedwater line are not considered within the scope of these
23   systems because they are normally open during operation and do not need to change state for
24   these systems to operate. However waterside valves up to the feedwater line are in scope if they
25   need to change state such as the HPCI injection valve.
26
27   The emergency generator dedicated to providing AC power to the high-pressure core spray
28   system is included in the scope of the HPCS. The HPCS system typically includes a "water leg"
29   pump to prevent water hammer in the HPCS piping to the reactor vessel. The "water leg" pump
30   and valves in the "water leg" pump flow path are ancillary components and are not included in the
31   scope of the HPCS system. Unavailability is not included while critical if the system is below
32   steam pressure specified in technical specifications at which the system can be operated.
33
34   **Oyster Creek**
35   For Oyster Creek the design does not include any high pressure injection system beyond the
36   normal feed water system. For the BWR high pressure injection system, Oyster Creek will
37   monitor the Core Spray system, a low pressure injection system.
38
39   **Train Determination**
40   The HPCI and HPCS systems are considered single-train systems. The booster pump and other
41   small pumps are ancillary components not used in determining the number of trains. The effect of
42   these pumps on system performance is included in the system indicator to the extent their failure
43   detracts from the ability of the system to perform its monitored function. For the FWCI system,
44   the number of trains is determined by the number of feedwater pumps. The number of condensate
45   and feedwater booster pumps are not used to determine the number of trains. It is recommended
46   that the DG that provides dedicated power to the HPCS system be monitored as a separate "train"

1 (or segment) for unavailability as the risk importance of the DG is less than the fluid parts of the
2 system.
3
4 **Reactor Core Isolation Cooling**
5 **(or Isolation Condenser)**
6
7 <u>**Scope**</u>
8 This system functions at high pressure to remove decay heat. The RCIC system also functions to
9 maintain reactor coolant inventory.
10
11 The function monitored for the indicator is the ability of the RCIC system to cool the reactor
12 vessel core and provide makeup water by taking a suction from the suppression pool (and from
13 the condensate storage tank, if required to meet the PRA success criteria and mission times) and
14 inject into the reactor vessel
15
16 The Reactor Core Isolation Cooling (RCIC) system turbine, governor, and associated piping and
17 valves for steam supply and exhaust are within the scope of the RCIC system. Valves in the
18 feedwater line are not considered within the scope of the RCIC system because they are normally
19 open during operation and do not have to change state for RCIC to perform its function.
20
21 The function monitored for the Isolation Condenser is the ability to cool the reactor by
22 transferring heat from the reactor to the Isolation Condenser water volume. The Isolation
23 Condenser and inlet valves are within the scope of Isolation Condenser system along with the
24 connecting active valve for isolation condenser makeup. Unavailability is not included while
25 critical if the system is below steam pressure specified in technical specifications at which the
26 system can be operated.
27
28 <u>**Train Determination**</u>
29 The RCIC system is considered a single-train system. The condensate and vacuum pumps are
30 ancillary components not used in determining the number of trains. The effect of these pumps on
31 RCIC performance is included in the system indicator to the extent that a component failure
32 results in an inability of the system to perform its monitored function.
33
34 For Isolation Condensers, a train is a flow path from the reactor to the isolation condenser back to
35 the reactor. The connecting active valve for isolation condenser makeup is included in the train.
36
37 **BWR Residual Heat Removal Systems**
38
39 <u>**Scope**</u>
40 The function monitored for the BWR residual heat removal (RHR) system is the ability of the
41 RHR system to provide suppression pool cooling. The pumps, heat exchangers, and associated
42 piping and valves for this function are included in the scope of the RHR system. If an RHR
43 system has pumps that do not perform a heat removal function (e.g. cannot connect to a heat
44 exchanger, dedicated LPCI pumps) they are not included in the scope of this indicator.
45
46

1   **Train Determination**
2   The number of trains in the RHR system is determined as follows. If the number of heat
3   exchangers and pumps is the same, the number of heat exchangers determines the number of
4   trains. If the number of heat exchangers and pumps are different, the number of trains should be
5   that used by the PRA model. Typically this would be two pumps and one heat exchanger forming
6   a train where the train is unavailable only if both pumps are unavailable, or two pumps and one
7   heat exchanger forming two trains with the heat exchanger as a shared component where a train is
8   unavailable if a pump is unavailable and both trains are unavailable if the heat exchanger is
9   unavailable.
10
11   **PWR High Pressure Safety Injection Systems**
12
13   **Scope**
14   These systems are used primarily to maintain reactor coolant inventory at high RCS pressures
15   following a loss of reactor coolant. HPSI system operation involves transferring an initial supply
16   of water from the refueling water storage tank (RWST) to cold leg piping of the reactor coolant
17   system. Once the RWST inventory is depleted, recirculation of water from the reactor building
18   emergency sump is required. The function monitored for HPSI is the ability of a HPSI train to
19   take a suction from the primary water source (typically, a borated water tank), or from the
20   containment emergency sump, and inject into the reactor coolant system.
21
22   The scope includes the pumps and associated piping and valves from both the refueling water
23   storage tank and from the containment sump to the pumps, and from the pumps into the reactor
24   coolant system piping. For plants where the high-pressure injection pump takes suction from the
25   residual heat removal pumps, the residual heat removal pump discharge header isolation valve to
26   the HPSI pump suction is included in the scope of HPSI system. Some components may be
27   included in the scope of more than one train. For example, cold-leg injection lines may be fed
28   from a common header that is supplied by both HPSI trains. In these cases, the effects of testing
29   or component failures in an injection line should be reported in both trains.
30
31   **Train Determination**
32   In general, the number of HPSI system trains is defined by the number of high head injection
33   paths that provide cold-leg and/or hot-leg injection capability, as applicable.
34
35   For Babcock and Wilcox (B&W) reactors, the design features centrifugal multi-stage pumps used
36   for high pressure injection (about 2,500 psig) and no hot-leg injection path. Recirculation from
37   the containment sump requires lining up the HPI pump suctions to the Low-Pressure Injection
38   (LPI) pump discharges for adequate NPSH. This is typically a two-train system, with an installed
39   spare pump (depending on plant-specific design) that can be aligned to either train.
40
41   For two-loop Westinghouse plants, the pumps operate at a lower pressure (about 1600 psig) and
42   there may be a hot-leg injection path in addition to a cold-leg injection path (both are included as
43   a part of the train).
44
45   For Westinghouse three-loop plants, the design features three centrifugal pumps that operate at
46   high pressure (about 2500 psig), a cold-leg injection path through the BIT (with two trains of

1 redundant valves), an alternate cold-leg injection path, and two hot-leg injection paths. One of the
2 pumps is considered an installed spare. Recirculation is provided by taking suction from the RHR
3 pump discharges. A train consists of a pump, the pump suction valves and boron injection tank
4 (BIT) injection line valves electrically associated with the pump, and the associated hot-leg
5 injection path. The alternate cold-leg injection path is required for recirculation, and should be
6 included in the train with which its isolation valve is electrically associated. This represents a
7 two-train HPSI system.
8
9 For Four-loop Westinghouse plants, the design features two centrifugal pumps that operate at
10 high pressure (about 2500 psig), two centrifugal pumps that operate at an intermediate pressure
11 (about 1600 psig), a BIT injection path (with two trains of injection valves), a cold-leg safety
12 injection path, and two hot-leg injection paths. Recirculation is provided by taking suction from
13 the RHR pump discharges. Each of two high pressure trains is comprised of a high pressure
14 centrifugal pump, the pump suction valves and BIT valves that are electrically associated with the
15 pump. Each of two intermediate pressure trains is comprised of the safety injection pump, the
16 suction valves and the hot-leg injection valves electrically associated with the pump. The cold-leg
17 safety injection path can be fed with either safety injection pump, thus it should be associated
18 with both intermediate pressure trains. This HPSI system is considered a four-train system for
19 monitoring purposes.
20
21 For Combustion Engineering (CE) plants, the design features two or three centrifugal pumps that
22 operate at intermediate pressure (about 1300 psig) and provide flow to four cold-leg injection
23 paths or two hot-leg injection paths. In most designs, the HPSI pumps take suction directly from
24 the containment sump for recirculation. In these cases, the sump suction valves are included
25 within the scope of the HPSI system. This is a two-train system (two trains of combined cold-leg
26 and hot-leg injection capability). One of the three pumps is typically an installed spare that can be
27 aligned to either train or only to one of the trains (depending on plant-specific design).
28
29 **PWR Auxiliary Feedwater Systems**
30
31 <u>**Scope**</u>
32 The function of the AFW system is to provide decay heat removal via the steam generators to
33 cool down and depressurize the reactor coolant system following a reactor trip. The mitigation of
34 ATWS events with the AFW system is not considered a function to be monitored by the MSPI.
35 (Note, however, that the FV values will include ATWS events).
36
37 The function monitored for the indicator is the ability of the AFW system to take a suction from a
38 water source (typically, the condensate storage tank and if required to meet the PRA success
39 criteria and mission time, from an alternate source) and to inject into at least one steam generator.
40
41 The scope of the auxiliary feedwater (AFW) or emergency feedwater (EFW) systems includes the
42 pumps and the components in the flow paths from the condensate storage tank and, if required,
43 the valve(s) that connect the alternative water source to the auxiliary feedwater system. The flow
44 path for the steam supply to a turbine driven pump is included from the steam source (main steam
45 lines) to the pump turbine. Pumps included in the Technical Specifications (subject to a Limiting
46 Condition for Operation) are included in the scope of this indicator. Some initiating events, such

1   as a feedwater line break, may require isolation of AFW flow to the affected steam generator to
2   prevent flow diversion from the unaffected steam generator. This function should be considered a
3   monitored function if it is required.
4

5   **Train Determination**
6   The number of trains is determined primarily by the number of parallel pumps. For example, a
7   system with three pumps is defined as a three-train system, whether it feeds two, three, or four
8   injection lines, and regardless of the flow capacity of the pumps. Some components may be
9   included in the scope of more than one train. For example, one set of flow regulating valves and
10   isolation valves in a three-pump, two-steam generator system are included in the motor-driven
11   pump train with which they are electrically associated, but they are also included (along with the
12   redundant set of valves) in the turbine-driven pump train. In these instances, the effects of testing
13   or failure of the valves should be reported in both affected trains. Similarly, when two trains
14   provide flow to a common header, the effect of isolation or flow regulating valve failures in paths
15   connected to the header should be considered in both trains.
16

17   **PWR Residual Heat Removal System**
18

19   **Scope**
20   The function monitored for the PWR residual heat removal (RHR) system is the long term decay
21   heat removal function to mitigate those transients that cannot rely on the steam generators alone
22   for decay heat removal. These typically include the low-pressure injection function and the
23   recirculation mode used to cool and recirculate water from the containment sump following
24   depletion of RWST inventory to provide decay heat removal. The pumps, heat exchangers, and
25   associated piping and valves for those functions are included in the scope of the RHR system.
26   Containment spray function should be included if it provides a risk significant decay heat removal
27   function. Containment spray systems that only provide containment pressure control are not
28   included.

29

30   **CE Designed NSSS**
31   CE ECCS designs differ from the description above.. CE designs run all ECCS pumps during the
32   injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low
33   Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps
34   are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the
35   containment sump. The HPSI pumps then provide the recirculation phase core injection, and the
36   CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the
37   cooled water into containment, support the core injection inventory cooling.
38

39   For the RHR function the CE plant design uses HPSI to take a suction from the sump, CS to cool
40   the fluid, and HPSI to inject at low pressure into the RCS. Due to these design differences, CE
41   plants with this design should monitor this function in the following manner. The two
42   containment spray pumps and associated coolers should be counted as two trains of RHR
43   providing the recirculation cooling. Therefore, for the CE designed plants two trains should be
44   monitored, as follows:
45   • Train 1 (recirculation mode) Consisting of the "A" containment spray pump, the required
46   spray pump heat exchanger and associated flow path valves.

- Train 2 (recirculation mode) Consisting of the "B" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

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The at power RHR function, is provided by two 100% low head safety injection pumps taking suction from the containment sump and injecting to the RCS at low pressure and with the heat exchanger function (containment sump water cooling) provided by four 50% containment recirculation spray system pumps and heat exchangers.

The RHR Performance Indicator should be calculated as follows. The low head safety injection and recirculation spray pumps and associated coolers should be counted as two trains of RHR providing the recirculation cooling, function as follows:

- "A" train consisting of the "A" LHSI pump, associated MOVS and the required "A" train recirculation spray pumps heat exchangers, and MOVS.

- "B" train consisting of the "B" LHSI pump, associated MOVS and the required "B" train recirculation spray pumps, heat exchangers, and MOVS.

Beaver Valley Unit 2

The at power RHR function, is provided by two 100% containment recirculation spray pumps taking suction from the containment sump, and injecting to the RCS at low pressure. The heat exchanger function is provided by two 100% capacity containment recirculation spray system heat exchangers, one per train. The RHR Performance Indicator should be calculated as follows. The two containment recirculation spray pumps and associated coolers should be counted as two trains of RHR providing the recirculation cooling.

Two trains should be monitored as follows:

- Train 1 (recirculation mode) Consisting of the containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger and MOVS.

- Train 2 (recirculation mode) Consisting of containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger, and MOVS.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers. Some components are used to provide more than one function of RHR. If a component cannot perform as designed, rendering its associated train incapable of meeting one of the monitored functions, then the train is considered to be failed. Unavailable hours would be reported as a result of the component failure.

Cooling Water Support System

Scope

The functions monitored for the cooling water support system are those functions that are necessary (i.e. Technical Specification-required) to provide for direct cooling of the components in the other monitored systems. It does not include indirect cooling provided by room coolers or other HVAC features.

1 Systems that provide this function typically include service water and component cooling water or
2 their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are
3 necessary to provide cooling to the other monitored systems are included in the system scope up
4 to, but not including, the last valve that connects the cooling water support system to components
5 in a single monitored system. This last valve is included in the other monitored system boundary.
6 If the last valve provides cooling to SSCs in more than one monitored system, then it is included
7 in the cooling water support system. Service water systems are typically open "raw water"
8 systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling
9 Water systems are typically closed "clean water" systems.
10
11 Valves in the cooling water support system that must close to ensure sufficient cooling to the
12 other monitored system components to meet risk significant functions are included in the system
13 boundary.
14
15 If a cooling water system provides cooling to only one monitored system, then it should be
16 included in the scope of that monitored system. Systems that are dedicated to cooling RHR heat
17 exchangers only are included in the cooling water support system scope.
18
19 **Train Determination**
20 The number of trains in the Cooling Water Support System will vary considerably from plant to
21 plant. The way these functions are modeled in the plant-specific PRA will determine a logical
22 approach for train determination. For example, if the PRA modeled separate pump and line
23 segments, then the number of pumps and line segments would be the number of trains.
24
25 **Clarifying Notes**
26 Service water pump strainers, cyclone separators, and traveling screens are not considered to be
27 monitored components and are therefore not part of URI. However, clogging of strainers and
28 screens that render the train unavailable to perform its monitored cooling function (which
29 includes the mission times) are included in UAI. Note, however, if the service water pumps fail
30 due to a problem with the strainers, cyclone separators, or traveling screens, the failure is included
31 in the URI.
32
33

1   **F 6.   CALCULATION OF THE BIRNBAUM IMPORTANCE BY REQUANTIFICATION**

2   This section provides an alternative to the method outlined in sections F 1.3.1-F 1.3.3 and F 2.3.1-
3   F 2.3.3. If you are using the method outlined in this section, do not perform the calculations
4   outlined in sections F 1.3.1-F 1.3.3 and F 2.3.1-F 2.3.3.

5   The truncation level used for the method described in this section should be sufficient to provide a
6   converged value of CDF. CDF is considered to be converged when decreasing the truncation level
7   by a decade results in a change in CDF of less than 5%.

8   The Birnbaum importance measure can be calculated from:

9    $$B = CDF_1 - CDF_0$$

10   or

11   $$B = \frac{CDF_1 - CDF_B}{1 - p}$$

12   Where

13   CDF_1 is the Core Damage Frequency with the failure probability for the component (any
14   representative basic event) set to one,

15   CDF_0 is the Core Damage Frequency with the failure probability for the component (any
16   representative basic event) set to zero,

17   CDF_B is the Base Case Core Damage Frequency,

18   and

19   p is the failure probability of the representative basic event.

20   As a special case, if the component is truncated from the base case then

21   $$CDF_B = CDF_0$$

22   and

23   $$B = CDF_1 - CDF_B$$

24
25   With the Birnbaum importance calculated directly by re-quantification, the CDE input values
26   must be calculated from this quantity.

27
28   The CDF value input to CDE for this method is the value of CDF_B from the baseline
29   quantification.

30
31   The value of UA or UR is taken from the representative basic event (p) used in the quantification
32   above. The FV value is then calculated from the expression

33
34   $$FV = \frac{B * p}{CDF}.$$

35
36

1
2

Figure F-1

ESFAS/Sequencer

DC Power

Class 1E Bus

EDG
Breaker

Lubrication System

Governor and Control
System

Exhaust
System

Control and Protection
System

Diesel Engine

Generator

Starting Air
System Receiver

Jacket
Water

Fuel Oil
System

Exciter and
Voltage
Regulator

Combustion Air
System and Supply

Isol. Valve

Fuel Oil Day
Tank

EDG Component Boundary

Room Cooling

Cooling Water

Fuel Transfer Pump*

3
4
5   * The Fuel Transfer Pump is included in the EDG System Boundary. See Section 5 for monitoring requirements.

1

Controls — ESFAS

Breaker

Motor Operator

Pump

Motor Driven Pump Boundary

2
3   Figure F-2

1

```
┌ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ┐
                                                        ┌──────────┐
        ┌──────────────────┐                            │  ESFAS   │
        │     Controls     │────────────────────────────│          │
        └──────────────────┘                            └──────────┘
                 │
        ┌──────────────────┐
        │     Breaker      │
        └──────────────────┘
                 │
        ┌──────────────────┐
        │  Motor Operator  │
        └──────────────────┘
                 │
              ◁▷ (valve symbol)

   MOV Boundary
└ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ─ ┘
```

2
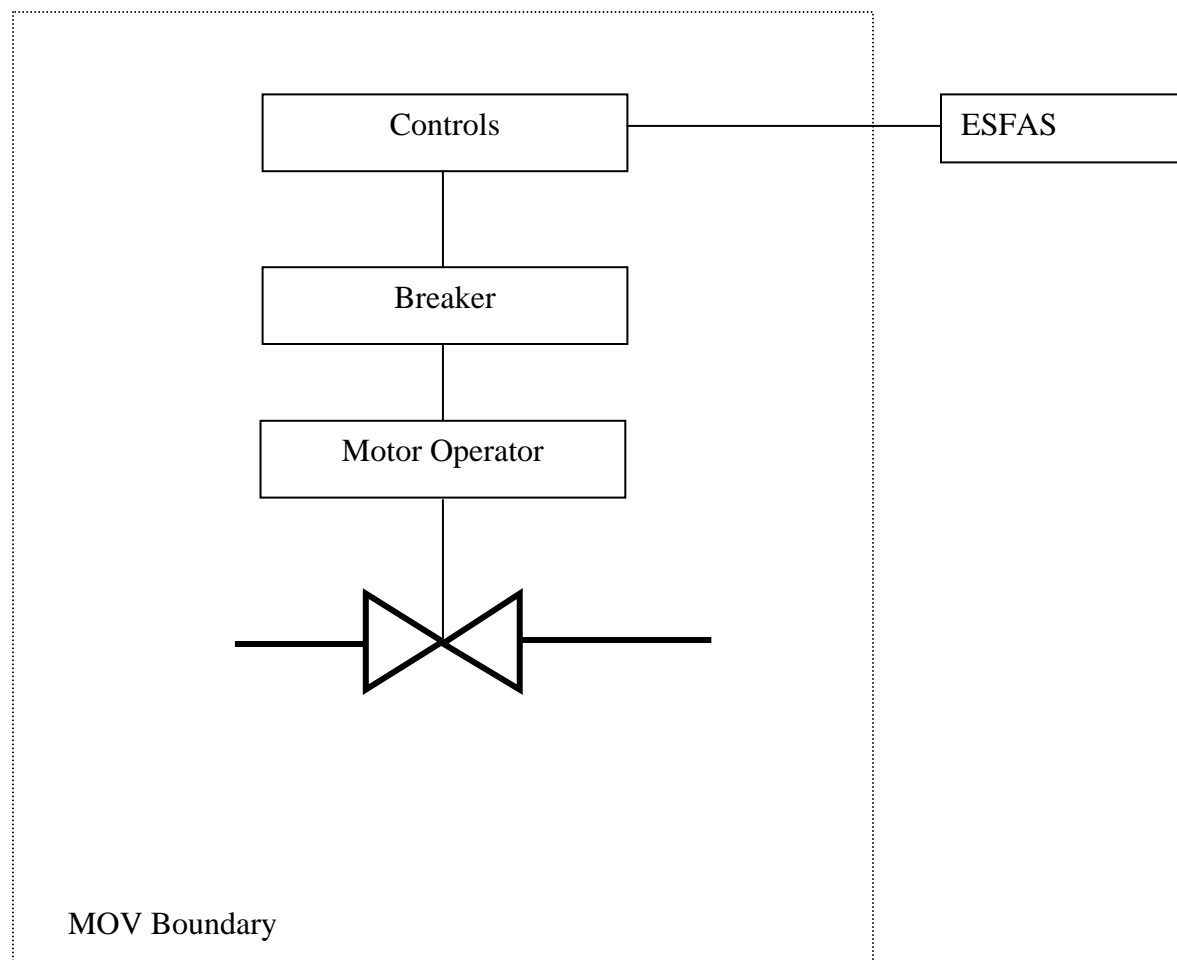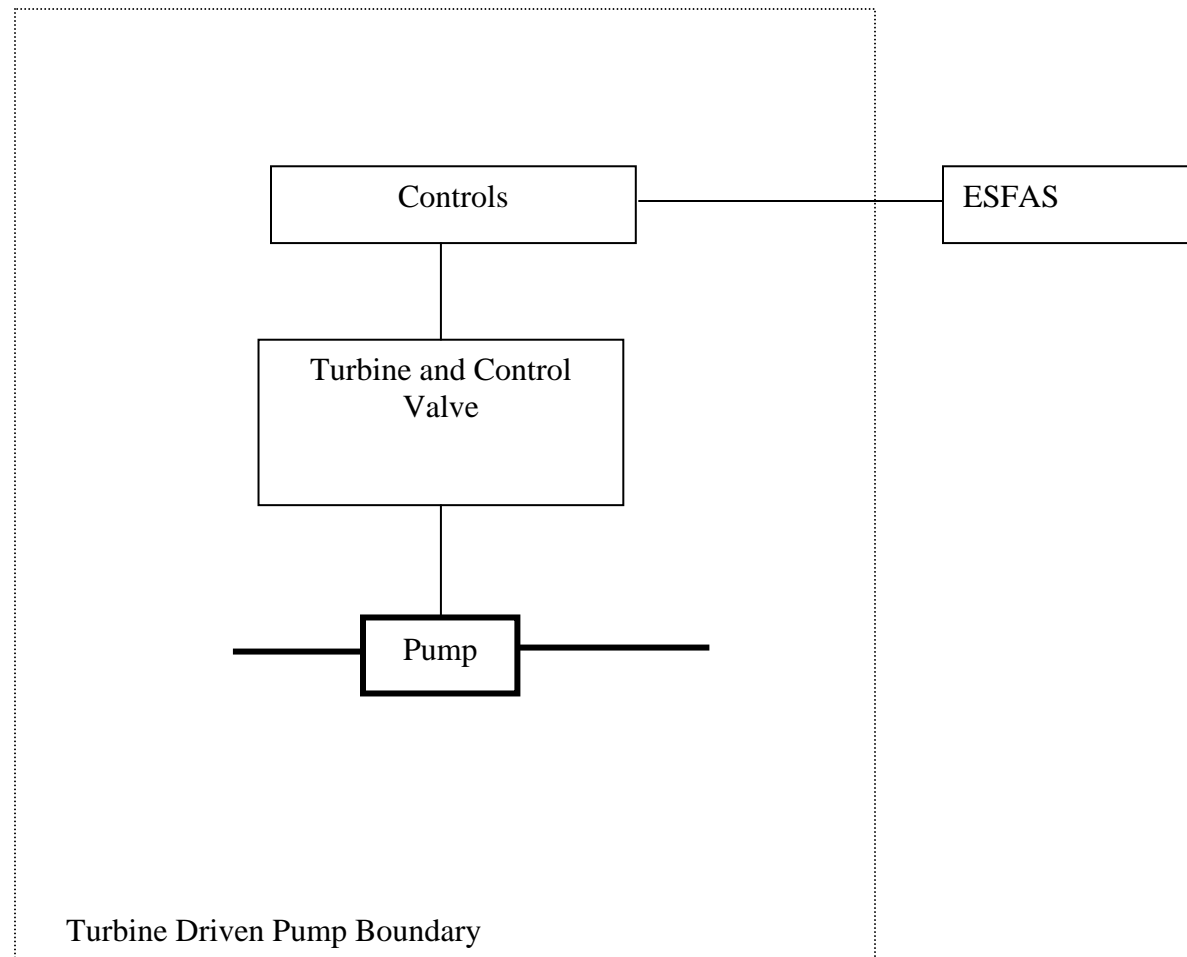3   Figure F-3
4
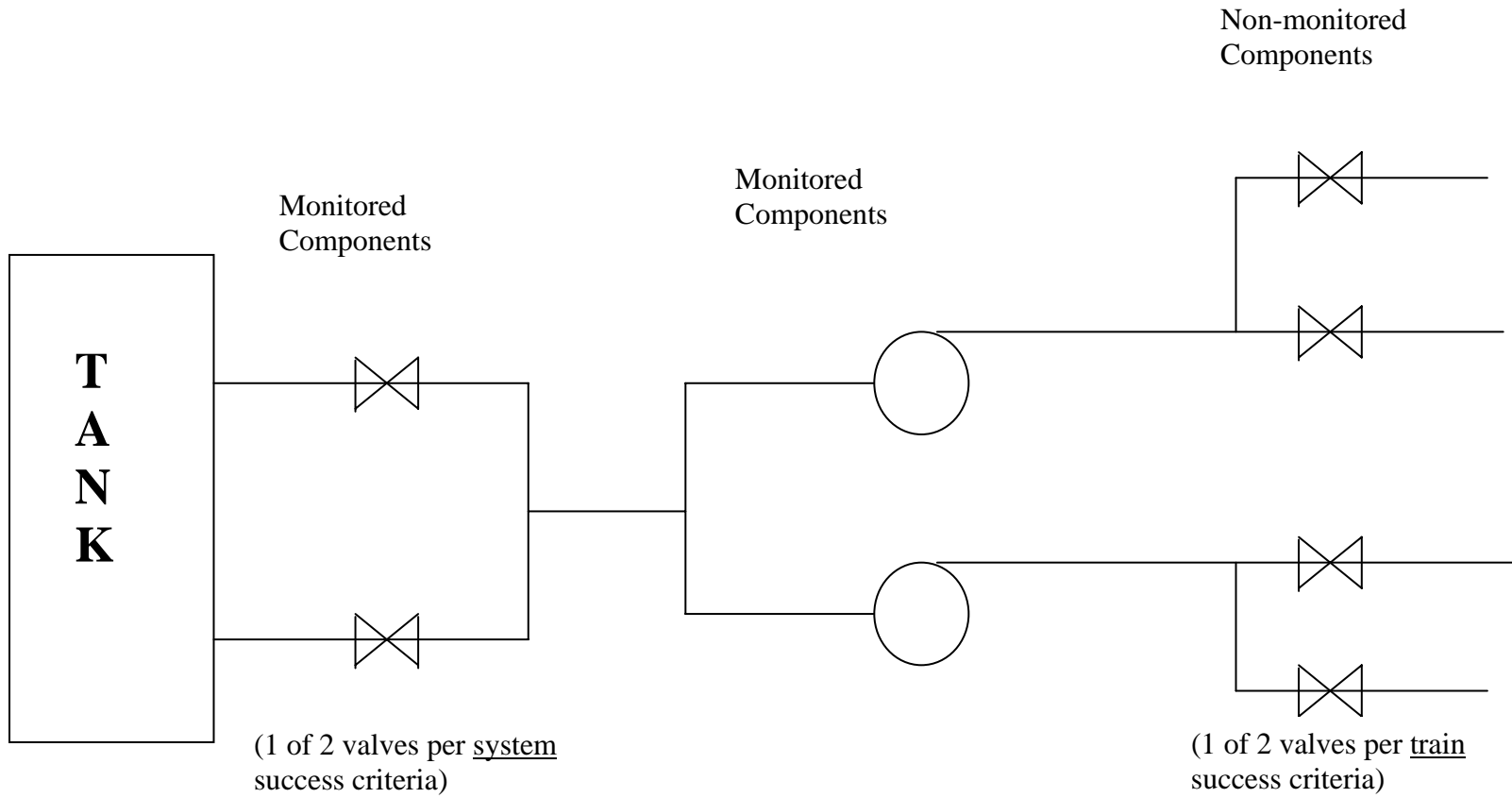
1

Figure F-4

1
2

Figure F-5

APPENDIX G

MSPI Basis Document Development

To implement the Mitigating Systems Performance Index (MSPI), Licensees will develop a plant specific basis document that documents the information and assumptions used to calculate the Reactor Oversight Program (ROP) MSPI. This basis document is necessary to support the NRC inspection process, and to record the assumptions and data used in developing the MSPI on each site. A summary of any changes to the basis document are noted in the comment section of the quarterly data submission to the NRC.

The Basis document will have two major sections. The first described below will document the information used in developing the MSPI. The second section will document the conformance of the plant specific PRA to the requirements that are outlined in this appendix.

G 1.   MSPI Data

The basis document provides a separate section for each monitored system as defined in Section 2.2 of NEI 99-02. The section for each monitored system contains the following subsections:

G 1.1   System Boundaries
This section contains a description of the boundaries for each train of the monitored system. A plant drawing or figure (training type figure) should be included and marked adequately (i.e., highlighted trains) to show the boundaries. The guidance for determining the boundaries is provided in Appendix F, Section 1.1 of NEI 99-02.

G 1.2   Risk Significant Functions
This section lists the risk significant functions for each train of the monitored system. Risk Significant Functions are defined in section 2.2 of NEI 99-02. Additional detail is given in Appendix F, Section 1.1.1 and Section 5 "Additional Guidance for Specific Systems". A single list for the system may be used as long as any differences between trains are clearly identified. This section may also be combined with the section on Success Criteria if a combination of information into a table format is desired. If none of the functions for the system are considered risk significant, identify the monitored function as defined in section F 1.1.1

G 1.3   Success Criteria
This section documents the success criteria as defined in Section 2.2 of NEI 99-02 for each of the identified monitored functions for the system. Additional detail is given in Appendix F, Section 2.1.1. **The criteria used are the documented PRA success criteria.**

- If the licensee has chosen to use design basis success criteria in the PRA, then provide a statement in this section that states the PRA uses design basis success criteria.
- If success criteria from the PRA are different from the design basis, then the specific differences from the design basis success criteria shall be documented in this section.

Provide the actual values used to characterize success such as: *The time required in the PRA for the EDG to successfully reach rated speed and voltage is 15 seconds.*
Where there are different success criteria for different monitored functions or different success criteria for different initiators within a monitored function, all should be recorded and the most restrictive shown as the one used.

G 1.4   Mission Time
This section documents the risk significant mission time, as defined in Section 2.3.6 of Appendix F, for each of the identified monitored functions identified for the system.

G 1.5   Monitored Components
This section documents the selection of monitored components as defined in Appendix F, Section 2.1.2 of NEI 99-02 in each train of the monitored system. A listing of all monitored pumps, breakers and EDG's should be included in this section. A listing of AOVs, HOVs , SOVs and MOVs that change state to achieve the monitored functions should be provided as potential monitored components. The basis for excluding valves in this list from monitoring should be provided. Component boundaries as described in Appendix F, Section 2.1.3 of NEI 99-02 should be included where appropriate.

G 1.6   Basis for Demands/Run Hours (estimate or actual)
The determination of reliability largely relies on the values of demands, run hours and failures of components to develop a failure rate. This section documents how the licensee will determine the demands on a component. Several methods may be used.
- Actual counting of demands/run hours during the reporting period
- An estimate of demands/run hours based on the number of times a procedure or other activities is performed plus actual ESF demands/run hours
- An estimate based on historical data over a year or more averaged for a quarterly average plus actual ESF demands/run hours

The method used, either actual or estimated values, shall be stated. If estimates are used for test or operational demands or run hours then the process used for developing the estimates shall be described and estimated values documented. If the estimates are based on performance of procedures, list the procedures and the frequencies of performance that were used to develop the estimates.

G 1.7   Short Duration Unavailability
This section provides a list of any periodic surveillances or evolutions of less than 15 minutes of unavailability that the licensee does not include in train unavailability. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact.

G 1.8   PRA Information used in the MSPI

G 1.8.1   Unavailability FV and UA
This section includes a table or spreadsheet that lists the basic events for unavailability for each train of the monitored systems. This listing should include the probability, FV, and FV/probability ratio and text description of the basic event or component ID. An example format

1   is provided as Table 1 at the end of this appendix. If the event chosen to represent the train is not
2   the event that results in the largest ratio, provide information that describes the basis for the
3   choice of the specific event that was used.
4

5   **G 1.8.1.1   Unavailability Baseline Data**
6   This section includes the baseline unavailability data by train for each monitored system. The
7   discussion should include the basis for the baseline values used. The detailed basis for the
8   baseline data may be included in an appendix to the MSPI Basis Document if desired.
9

10   The basis document should include the specific values for the planned and unplanned
11   unavailability baseline values that are used for each train or segment in the system.
12

13   **G 1.8.1.2   Treatment of Support System Initiator(s)**
14   This section documents whether the cooling water systems are an initiator or not. This section
15   provides a description of how the plant will include the support system initiator(s) as described
16   in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the
17   calculation must be documented in accordance with plant processes and referred to here. The
18   results should also be included in this section. A sample table format for presenting the results of
19   a plant specific calculation for those plants that do not explicitly model the effect on the initiating
20   event contribution to risk is shown in Table 4 at the end of this appendix.
21

22   **G 1.8.2   Unreliability FV and UR**
23   There are two options described in Appendix F for the selection of FV and UR values, the
24   selected option should be identified in this section. This section also includes a table or
25   spreadsheet that lists the PRA information for each monitored component. This listing should
26   include the Component ID, event probability, FV, the common cause adjustment factor and
27   FV/probability ratio and text description of the basic event or component ID. An example format
28   is provided as Table 2 at the end of this appendix. If individual failure mode ratios (vice the
29   maximum ratio) will be used in the calculation of MSPI, then each failure mode for each
30   component will me listed in the table.
31

32   A separate table should be provided in an appendix to the basis document that provides the
33   complete set of basic events for each component. An example of this for one component is
34   shown in Table 3 at the end of this appendix. Only the basic event chosen for the MSPI
35   calculation requires completion of all table entries.
36

37   **G 1.8.2.1   Treatment of Support System Initiator(s)**
38   This section documents whether the cooling water systems are an initiator or not. This section
39   provides a description of how the plant will include the support system initiator(s) as described
40   in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the
41   calculation must be documented in accordance with plant processes and referred to here. The
42   results should also be included in this section. A sample table format for presenting the results of
43   a plant specific calculation for those plants that do not explicitly model the effect on the initiating
44   event contribution to risk is shown in Table 4 at the end of this appendix.
45

G 1.8.2.2   Calculation of Common Cause Factor

This section contains the description of how the plant will determine the common cause factor as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section.

G 1.9   Assumptions

This section documents any specific assumptions made in determination of the MSPI information that may need to be documented. Causes for documentation in this section could be special methods of counting hours or runtimes based on plant specific designs or processes, or other instances not clearly covered by the guidance in NEI 99-02.

G 2.   PRA Requirements

G 2.1 Discussion

The MSPI application can be considered a Phase 2 application under the NRC's phased approach to PRA quality. The MSPI is an index that is based on an internal initiating events, full-power PRA, for which the ASME Standard has been written. The Standard has been endorsed by the staff in RG 1.200, which has been issued for trial use.

Licensees should assure that their PRA is of sufficient technical adequacy to support the MSPI application by one of the following alternatives:

G 2.1.1   Alternative A (Consistent with MSPI PRA Task Group recommendations)

a)   Resolve the peer review Facts and Observations (F&Os) for the plant PRA that are classified as being in category A or B, or document the basis for a determination that any open A or B F&Os will not significantly impact the MSPI calculation. Open A or B F&Os are significant if collectively their resolution impacts any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an open A or B F&O cannot be resolved by April 1, 2006 and significantly impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum value from the associated cross comparison group for pumps/diesels and 3 times the plant values for valves/breakers should be used in the MSPI calculation at the index, system or component level, as appropriate, until the F&O is resolved.

And

b)   Perform a self assessment using the NEI-00-02 process as modified by Appendix B of RG 1.200 for the ASME PRA Standard supporting level requirements identified by the MSPI PRA task group and resolve any identified issues or document the basis for a determination that any open issues will not significantly impact the MSPI calculation. Identified issues are considered significant if they impact any Birnbaum values used in MSPI by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify the impact. If an identified issue cannot be resolved by April 1, 2006 and significantly impacts the MSPI

1   calculation, a modified Birnbaum value equal to a factor of 3 times the median Birnbaum
2   value from the associated cross comparison group for pumps/diesels and 3 times the plant
3   value for valves/breakers should be used in the MSPI calculation at the index, system or
4   component level, as appropriate, until the issue is resolved.
5
6   **G 2.1.2   Alternative B (Consistent with RG 1.174 guidance)**
7
8   a)   Resolve the peer review Facts and Observations (F&Os) for the plant PRA that are
9   classified as being in category A or B, or document the basis for a determination that any
10   open A or B F&Os will not significantly impact the MSPI calculation. Open A or B F&Os
11   are significant if collectively their resolution impacts any Birnbaum values used in MSPI
12   by more than a factor of 3. Appropriate sensitivity studies may be performed to quantify
13   the impact. If an open A or B F&O cannot be resolved by April 1, 2006 and significantly
14   impacts the MSPI calculation, a modified Birnbaum value equal to a factor of 3 times the
15   median Birnbaum value from the associated cross comparison group for pumps/diesels and
16   3 times the plant values for valves/breakers should be used in the MSPI calculation at the
17   index, system or component level, as appropriate, until the F&O is resolved.
18
19
20   **And**
21
22   b)   Disposition any candidate outlier issues identified by the industry PRA cross comparison
23   activity. The disposition of candidate outlier issues can be accomplished by:
24
25   •   Correcting or updating the PRA model;
26   •   Demonstrating that outlier identification was due to valid design or PRA modeling
27   methods; or
28   •   Using a modified Birnbaum value equal to a factor of 3 times the median value from the
29   associated cross comparison group for pumps/diesels and 3 times the plant value for
30   valves/breakers until the PRA model is corrected or updated.
31
32
33   **G 2.2 PRA MSPI Documentation Requirements**
34
35   A.   Licensees should provide a summary of their PRA models to include the following:
36   1. Approved version and date used to develop MSPI data
37   2. Plant base CDF for MSPI
38   3. Truncation level used to develop MSPI data
39
40   B.   Licensees should document the technical adequacy of their PRA models, including:
41   1. Justification for any open category A or B F&Os that will not be resolved prior to
42   April 1, 2006.
43   2. Justification for any open issues from:
44   a. the self-assessment performed for the supporting requirements (SR) identified in
45   Table 5, taking into consideration Appendix B of RG 1.200 (trial), with particular
46   attention to the notes in Table 4 of the MSPI PRA task group report.

-- OR --
b. identification of any candidate outliers for the plant from the group cross-comparison studies.

C.   Licensees should document in their PRA archival documentation:

   1. A description of the resolution of the A and B category F&Os identified by the peer review team.
   2. Technical bases for the PRA.

1
G 3. TABLES
2
3
4 **Table G 1 Unavailability Data HPSI (one table per system)**

Train	Basic Event Name	Basic Event Description	Basic Event Probability (UAP)	Basic Event FVUAP [1]	FVUAP/UAP
A	1SIAP02----MP6CM	HPSI Pump A Unavailable Due to Mntc	3.20E-03	3.19E-03	9.97E-01
B	1SIBP02----MP6CM	HPSI Pump B Unavailable Due to Mntc	3.20E-03	3.85E-03	1.20E+00

5 **1. Adjusted for IEF correction if used**
6
7 **Table G 2 – AFW System Monitored Component PRA Information**

Component	Basic Event	Description	Basic Event Probability (URPC)	Basic Event FVURC	[FV/UR]*ind*	CC Adjustment Factor (A)	CC Adjustment Used	Adjusted Birnbaum
1MAFAP01	1AFASYS----AFACM	Train A Auxiliary Feedwater Pump Fails to Start	2.75E-03	2.33E-02	8.49E+00	1	Generic	1.1E-04
1MAFBP01	1AFBP01----MPAFS	Train B Auxiliary Feedwater Pump Fails to Start	6.73E-04	4.44E-02	6.59E+01	1.25	Generic	1.1E-03
1MAFNP01	1AFNSYS----AFNCM	Train N Auxiliary Feedwater Pump Fails to Start	1.05E-03	1.10E-02	1.05E+01	1.25	Generic	1.7E-04
1JCTAHV0001	1CTAHV001--MV-FO	CST to AFW Pump N Supply Valve HV1 Fails to Open (Local Fault)	3.17E-03	2.48E-02	7.83E+00	2	Generic	2.0E-04
1JCTAHV0004	1CTAHV004--MV-FO	CST to AFW Pump N Supply Valve HV4 Fails to Open (Local Fault)	3.17E-03	2.48E-02	7.83E+00	2	Generic	2.0E-04

8
9

1 **Table G 3 - Unreliability Data (one table per monitored component)**
2 **Component Name and ID:** HPSI Pump B - 1SIBP02

Basic Event Name	Basic Event Description	Basic Event Probability (URPC)	Basic Event FVURC[1]	[FV/UR]in d	Common Cause Adjustment Factor (CCF)	Common Cause Adjustment Generic or Plant Specific	Adjusted Birnbaum
1SIBP02---XCYXOR	HPSI Pump B Fails to Start Due to Override Contact Failure	6.81E-04	7.71E-04	1.13E+00	3.0	Generic	5.0E-05
1SIBP02----MPAFS	HPSI Pump B Fails to Start (Local Fault)	6.73E-04	7.62E-04	1.13E+00			
1SIBP02----MP-FR	HPSI Pump B Fails to Run	4.80E-04	5.33E-04	1.11E+00			
1SABHP-K125RXAFT	HPSI Pump B Fails to Start Due to K125 Failure	3.27E-04	3.56E-04	1.09E+00			
1SIBP02----CB0CM	HPSI Pump B Circuit Breaker (PBB-S04E) Unavailable Due to Mntc	2.20E-04	2.32E-04	1.05E+00			
1SIBP02----CBBFT	HPSI Pump B Circuit Breaker (PBB-S04E) Fails to Close (Local Fault)	2.04E-04	2.14E-04	1.05E+00			

3 **1. Adjusted for IEF correction if used**
4
5 **Table G 4 Cooling Water Support System FV Calculation Results (one table per train/component/failure mode)**

FVa (or FVc)	FVie	FVsa (or FVsc)	UA (or UR)	Calculated FV (per appendix F) (result is put in Basic Event column of table 1 or table 2 as appropriate)

6

| TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment ||
Supporting Requirement	Comments
IE-A4	Focus on plant specific initiators and special initiators, especially loss of DC bus, Loss of AC bus, or Loss of room cooling type initiators
IE-A7	Category I in general. However, precursors to losses of cooling water systems in particular, e.g., from fouling of intake structures, may indicate potential failure mechanisms to be taken into account in the system analysis (IE-C6, 7, 8, 9)
IE-A9	Category II for plants that choose fault trees to model support systems. Watch for initiating event frequencies that are substantially (e.g., more than 3 times) below generic values.
IE-C1	Focus on loss of offsite power (LOOP) frequency as a function of duration
IE-C2	Focus on LOOP and medium and small LOCA frequencies including stuck open PORVs
IE-C6	For plants that choose fault trees for support systems, attention to loss of cooling systems initiators.
IE-C9	Category II for plants that choose fault trees for support systems. Pay attention to initiating event frequencies that are substantially (i.e., more than 3 times) below generic values
AS-A3	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A4	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A5	Focus on credit for alternate sources, e.g., gas turbines, CRD, fire water, SW cross-tie, recovery of FW
AS-A9	Category II for MSPI systems and components and for systems such as CRD, fire water, SW cross-tie, recovery of FW
AS-A10	Category II in particular for alternate systems where the operator actions may be significantly different, e.g., more complex, more time limited.
AS-B3	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
AS-B6	Focus on (a) time phasing in LOOP/SBO sequences, including battery depletion, and (c) adequacy of CRD as an adequate injection source.
SC-A4	Focus on modeling of shared systems and cross-ties in multi-unit sites
SC-B1	Focus on proper application of the computer codes for T/H calculations, especially for LOCA, IORV, SORV, and F&B scenarios.
SC-C1	Category II

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
Supporting Requirement	**Comments**
SY-A4	Category II for MSPI systems and components
SY-A11	Focus on (d) modeling of shared systems
SY-A20	Focus on credit for alternate injection systems, alternate seal cooling
SY-B1	Should include EDG, AFW, HPI, RHR CCFs
SY-B5	Focus on dependencies of support systems (especially cooling water systems) to the initiating events
SY-B9	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
SY-B15	Focus on credit for injection post-venting (NPSH issues, environmental survivability, etc.)
HR-E1	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-E2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G1	Category II , though Category I for the critical HEPs would produce a more sensitive MSPI (i.e., fewer failures to change a color)
HR-G2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G3	Category I. See note on HR-G1. Attention to credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-G5	Category II. See note on HR-G1.
HR-H2	Focus on credit for cross ties, depressurization, use of alternate sources, venting, core cooling recovery, initiation of F&B
HR-H3	The use of some systems may be treated as a recovery action in a PRA, even though the system may be addressed in the same procedure as a human action modeled in the accident sequence model (e.g., recovery of feedwater may be addressed in the same procedure as feed and bleed). Neglecting the cognitive dependency can significantly decrease the significance of the sequence.
DA-B1	Focus on service condition (clean vs untreated water) for SW systems
DA-C1	Focus on LOOP recovery
DA-C15	Focus on recovery from LOSP and loss of SW events
DA-D1	For BWRs with isolation condenser, focus on the likelihood of a stuck open SRV
QU-B2	Truncation limits should be chosen to be appropriate for F-V calculations.

TABLE G 5. ASME PRA Standard Supporting Requirements Requiring Self-Assessment	
Supporting Requirement	**Comments**
QU-B3	This is an MSPI implementation concern and should be addressed in the guidance document. Truncation limits should be chosen to be appropriate for F-V calculations.
QU-D3	Understanding the differences between plant models, particularly as they affect the MSPI, is important for the proposed approach to the identification of outliers recommended by the task group.
QU-D5	Category II for those who have used fault tree models to address support system initiators.
QU-E4	Category II for the issues that directly affect the MSPI